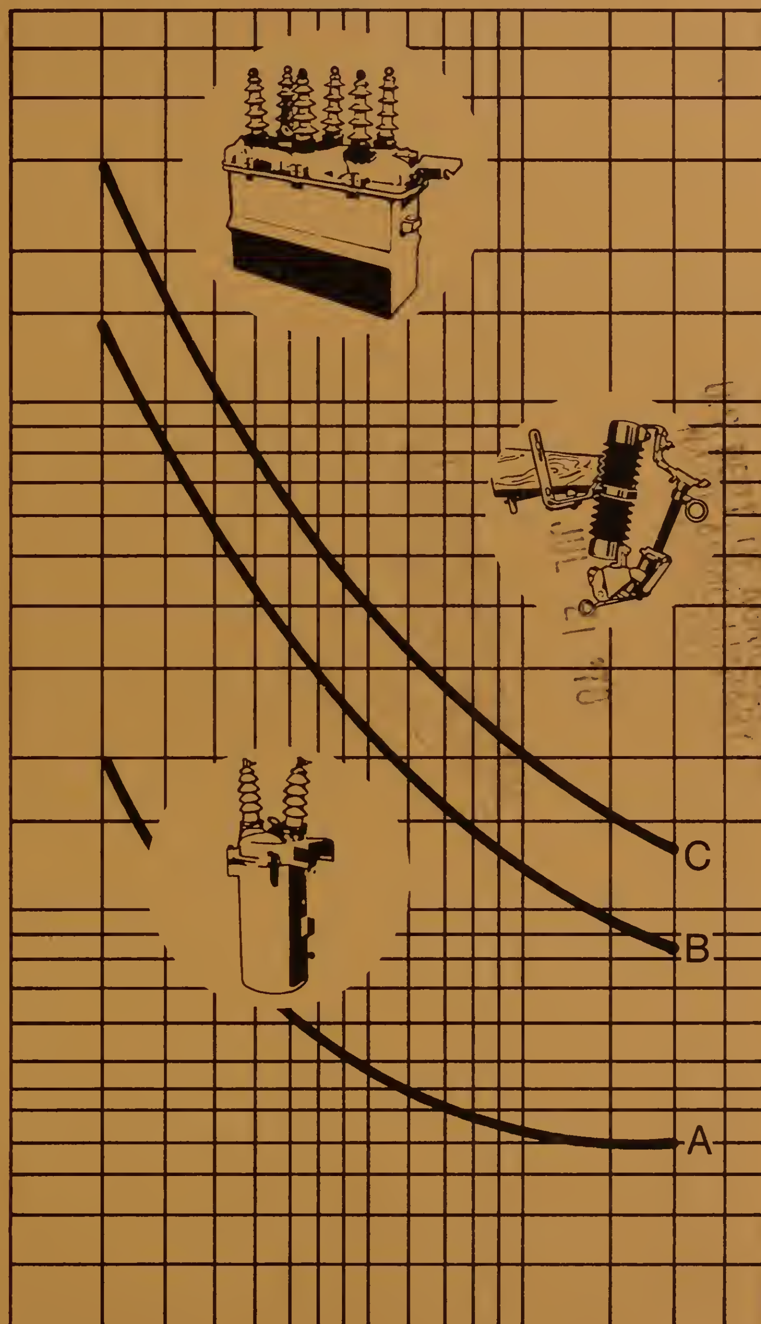
GUIDE FOR MAKING A SECTIONALIZING STUDY ON RURAL ELECTRIC SYSTEMS



REA BULLETIN 61-2

RURAL ELECTRIFICATION ADMINISTRATION/U.S. DEPARTMENT OF AGRICULTURE

MARCH 1978

FOREWORD

All electric systems are susceptible to outages resulting from faults caused by trees, wind, ice, animals, human error, and insulation failure. These faults must be removed from the system by fuses, circuit breakers, or circuit reclosers. The proper application of these sectionalizing devices will isolate the faults and limit their effect to the fewest practical number of consumers. The methods used to calculate fault currents and to apply sectionalizing devices on rural distribution systems are described in detail in this bulletin.

Load growth in rural areas requires the construction of new higher capacity transmission and distribution facilities which results in increasing short-circuit currents on rural distribution lines and at substations. This bulletin has been revised recognizing that fault currents are higher than in the past. It also discusses new higher capacity current interrupting devices, and makes some recommendations for their application. The bulletin also recognizes that rural underground distribution systems are more extensive than in the past.

A new tabular method of calculating available fault current has been developed. The graphical methods of the previous bulletin have been retained as appendices of this bulletin.

The bulletin has been revised to include metric units for distance measurements. Conductor size designations are being retained in customary AWG because there has not been the necessary industry standardization of metric wire sizes. If it is necessary to convert from metric units to customary units, conversion factors are included in the fault current calculation tables and elsewhere as applicable.

This bulletin supersedes Bulletin 61-2, dated March 1958, and its supplements.

Richard F. Richter

Assistant Administrator - Electric

Index:
  DESIGN, SYSTEM:
    Sectionalizing Study Procedure
  MATERIALS AND EQUIPMENT:
    Selection and Locating of Sectionalizing Equipment
  SECTIONALIZING STUDIES AND EQUIPMENT

TABLE OF CONTENTS

Page

CHAPTER I

INTRODUCTION

A. General

This bulletin is a guide for making sectionalizing studies on rural electric distribution systems. It also makes some suggestions for selecting and locating sectionalizing equipment.

It is not the purpose of this bulletin to give a complete discussion of overcurrent protection, including all the types of relaying which are being used on transmission and distribution systems. The material presented here will be limited to time-overcurrent protection and sectionalizing of radial distribution circuits.

The entire bulletin should be read before any of its principles are applied. One should not extract parts of the bulletin without fully comprehending how such parts relate to the total sectionalizing program. To do so could lead to misapplication of sectionalizing devices. All analyses are based upon, and pertain to, rural circuits which conform to the specifications of standard REA construction. The methods presented in this bulletin may yield inaccurate results if applied to systems employing different construction standards.

The bulletin is written partly in the form of a textbook and partly in the form of instructions on methods and procedures. Every effort has been made to make the text as simple as possible. It is not necessary to have a knowledge of the theory of symmetrical components to use the methods recommended in this bulletin. However, this bulletin should not preclude a more rigorous analysis of circuits by engineers who possess a knowledge of symmetrical components. Modern digital computers with well developed programs are an aid in calculating fault currents and can yield accuracies as great as the accuracy of the input data. However, where access to a computer operation is not available, the slide rule (or calculator) and methods outlined in this bulletin are sufficiently accurate.

The engineer familiar with symmetrical components will find that some of the formulas in this text have a different form than those with which he is familiar. These changes have been made in the interest of simplicity for the application to REA borrower systems. For the purpose of simplification, various limitations are established and assumptions are made. These simplifying assumptions and limitations are explained where applicable and should be noted carefully by anyone solving an actual problem.

Throughout the bulletin, it is assumed that the nominal distribution voltage is constant from the distribution substation bus to the most remote part of the circuit and that this voltage does not vary with load cycles or during faults. Although these are not precisely valid assumptions, they are sufficiently accurate so as not to significantly affect the results.

In order to provide ease in checking, engineers making sectionalizing studies for REA borrowers should prepare the study in the same general format as shown in this bulletin.

Overcurrent protection of electrical circuits is needed to protect conductors and equipment from thermal damage caused by excessive current flow. Excessive current can be caused by overload or by system short circuits (faults). Overloads should be minimized by proper design and operating practices. Overcurrent protective devices can, in some cases, be set to provide overload protection. However, in other instances, this would require the selection and setting of protective devices at such a low current level that the circuit could be prohibited from operating at its maximum design kVA. Therefore, the term sectionalizing will be used to define the action of automatic overcurrent protection devices operating during system short circuit conditions.

Short circuits (faults) can be classified into two general categories. These are non-persistent (temporary) faults and persistent (permanent) faults. Non-persistent faults are those which will cease if the line is quickly deenergized. Persistent faults are those which after deenergization require repair or replacement of a part of the distribution system before reenergization can take place. Studies have shown that 80% to 90% of faults occurring on an overhead rural distribution system are of the non-persistent type.

The objectives of distribution system sectionalizing are:

1. To attain the minimum practical minutes outage per consumer per year.

2. To attain the minimum practical expense of service restoration after outages which are caused by primary line faults.

3. To minimize damage to primary lines and apparatus during faults.

4. To minimize the probability of a hazardous voltage at ground level or on grounded objects interconnected with the system neutral.

The first two objectives are accomplished by preventing non-persistent faults from developing into permanent faults and by deenergizing only the shortest line section which is practical after a persistent fault. The other two objectives are related to the first two and are achieved by the judicious selection and setting of operating characteristics of overcurrent protective devices by the system protection engineer. The system protection engineer should also attempt to achieve these objectives with the minimum practical amount of capital invested in system overcurrent protection.

Sectionalizing studies should be reviewed at frequent intervals in order to insure that they are adequate. These reviews can usually be performed by the system staff engineer or operating superintendent. The review

should insure that load currents have not grown beyond the continuous current rating of sectionalizing devices. In rapid load growth areas an annual review of sectionalizing device load-carrying capability may be required.

Whenever major system design changes are being planned, a sectionalizing study should be included as part of the work. Major design changes would include:

1. Increasing substation transformer capacity.

2. Constructing a new substation.

3. Constructing new transmission or subtransmission facilities.

4. Increasing main line feeder capacity by installing larger conductor.

5. Increasing feeder capacity by converting to a higher distribution voltage.

Whenever the management of a distribution system is notified by its power supplier that significantly higher short-circuit currents will be available due to the power supplier system improvement program, a new sectionalizing study should be performed.

In high load growth areas, primary load current and system short-circuit currents are changing rapidly. To provide system protection and good consumer service reliability, sectionalizing studies should be reviewed and updated frequently.

B. Summary of Steps in Making a Sectionalizing Study

The following is a list of the individual steps involved in making a sectionalizing study. Each of these steps will be explained in example studies later in this bulletin. These steps have been summarized to provide an overview of the procedure of making a sectionalizing study.

1. Obtain complete data on the power system and on all sectionalizing devices which are likely to be specified.

2. Make a tentative location of the sectionalizing devices after:

   a. Study of the lines, both on a map and in the field.
   b. Talks with the operating personnel.
   c. Reviewing system outage records.

3. Calculate maximum and minimum fault currents at each tentative sectionalizing point and at the ends of the lines. Calculate line-to-ground, three-phase, and/or line-to-line fault currents. (Refer to Table I, II, III, and IV for formulas.)

4. Select the devices at the substation to give adequate protection to the substation transformers from fault currents on the lines.

5. Coordinate the sectionalizing devices from the substation out, or from the ends back to the substation. Revise the tentative locations as necessary.

6. Check the selected devices for voltage rating, continuous current rating, interrupting current rating, and minimum pickup rating. Make sure each device is applied within rating and will respond to minimum fault current in its zone of protection.

7. Prepare written instructions and new circuit diagrams (or update existing circuit diagrams) for the operating personnel regarding the disposition of existing sectionalizing devices and the identification and location of proposed new sectionalizing devices.

C. Data Necessary

1. Distribution System Information

   a. Circuit diagram of system prepared in accordance with REA Bulletin 60-1.

   b. Locations of critical loads to which a lengthy power interruption would be costly or detrimental.

   c. Locations and sizes of large power loads.

   d. Locations of internally fused transformers larger than 10 kVA.

   e. Maximum load currents at time of study for each proposed sectionalizing point.

   f. Location of all transitions from overhead construction to underground construction and vice versa.

2. Substation Information (for each substation)

   a. Schematic diagram showing transformer connections, protective devices, outgoing circuits and all sectionalizing devices within approximately two kilometers of substation.

   b. Substation transformer capacity, voltages, and percent impedance.

   c. Substation transformer time-current damage curve. If this is not available, select the appropriate curve from Figures 26 or 27 or consult curve, Figure 28, ANSI Standard C57-92, Guide for Loading Oil Immersed Distribution and Power Transformers.

3. Power Supply Information for Each Substation or Metering Point.

   a. Line-to-line supply side voltage.

   b. Source impedance. This may be given by the Power Supplier

directly in ohms or per unit impedance, or may be given in maximum three-phase, line-to-ground, or line-to-line fault current from which the source impedance can be calculated. Refer to Table I, II, and III.

c. Maximum size of supply-side fuse or other protective device permitted by power supplier.

d. Make and type of supply-side fuse if specified by power supplier.

e. Protection provided by power supplier.

4. Power Supply Information for Each Substation Supplied by Isolated Generation

a. Distance between substation and power plant.

b. Line-to-line supply voltage.

c. Size and configuration of circuit between substation and power plant.

d. For each generator.

kVA capacity

% direct axis transient reactance

% direct axis synchronous reactance

% negative sequence reactance

Type of prime mover

e. Generators normally running during minimum and maximum loads.

f. Maximum size of supply-side fuse permitted by power supplier.

g. Make and type of supply-side fuse if specified by supplier.

h. Protection provided by power supplier.

5. Equipment Information (obtain from manufacturer)

a. Supply-side fuse make, type, time-current characteristic curves and ratings.

b. Automatic circuit recloser make, type, table of ratings and time-current characteristic curves.

c. Automatic line sectionalizer make, type and table of ratings.

d. Distribution line sectionalizing fuses make, type and time-current characteristic curves.

e. Distribution transformer external and internal fuses make, type and time-current characteristic curves. This will be required for only the largest distribution transformer fuse in each line section protected by a line sectionalizing device.

D. Location of Sectionalizing Devices

The first step is to make a tentative location of sectionalizing devices. These tentative locations may be revised after the short circuit currents are calculated and load current checked. Individual judgment must be used for each case, but the following points may be helpful:

1. The use of more than three or four reclosers or other automatic sectionalizing devices in series on any circuit usually is not justified. Non-automatic devices such as disconnect switches, spaced between the automatic devices will be very helpful in system operations and their liberal use is recommended.

2. Branch lines connected to the main circuit vary in their importance to circuit service reliability, depending on their length and where they are connected to the main circuit. Branch lines tapped off the first main line section have the most potential for impairing service reliability and even short taps (e.g., one or two kilometers) should be sectionalized if possible. Branch lines off the second, third, and fourth main line section have a successively lesser potential for impairing service reliability and they can be correspondingly longer in length or exposure before a sectionalizing device is justified.

3. Any branch line exposed to unusually hazardous conditions should be separated from the remainder of the system by a sectionalizing device.

4. Where main lines branch, a sectionalizing device should be used in at least one line and preferably in both, at or near the junction point.

5. The sectionalizing device should be accessible from roads open the year-around.

6. The sectionalizing device should be located near a member with a telephone if possible.

7. The sectionalizing device should not disrupt service to important loads. If a sectionalizing device is to be located near an important load, it should be placed beyond the load. This will give it maximum protection.

E. Suggested Outline for Sectionalizing Study Report

1. Scope of Study.

2. Tabulation of sectionalizing devices to be purchased.

3. Sectionalizing device schedule for each substation area.

4. Cost estimate - (Labor and material of installing new sectionalizing devices plus changing and converting existing devices)

5. Schematic diagram and coordination chart for substation protective devices for line-to-line and line-to-ground fault conditions. Include coordination chart for three-phase fault conditions for small systems and for transformers which are not delta-wye connected.

6. Detailed impedance and fault current calculations for source and substation transformers up to load side bus.

7. Time-current characteristic curves for sectionalizing devices used on system.

8. Instructions to the borrower.

9. Exhibit 1 - Short circuit current data sheet.

10. Exhibit 2 - Circuit diagram of system prepared in accordance with REA Bulletin 60-1, "Circuit Diagrams, Electrical Data Sheets and other Drawings for Systems of Electric Borrowers," showing location and sizes of sectionalizing devices, maximum and minimum fault currents, etc. (Sufficient copies should be supplied for servicemen, line crews, etc.)

CHAPTER II

DETERMINATION OF FAULT CURRENTS

A. General

1. Assumptions

The discussion and the information in this chapter are based on the following assumptions:

a. The frequency of the system is 60 hertz.

b. All distribution lines have multigrounded neutral conductors.

c. Underground lines are made up of direct-buried, single-phase cables with aluminum conductors and bare concentric neutrals. The voltage rating of the cable is 25 kV or less.

d. The substation transformers are connected delta on the supply-side and wye-grounded on the load side.

e. The system is radial (i.e., no connected loops). If there is more than one source of supply, they are not interconnected.

2. Fault Current

While making a sectionalizing study it is necessary to calculate both the maximum fault current and the minimum fault current at each sectionalizing point. In addition, the minimum fault current must be calculated for the end of each line. The method of calculating maximum and minimum fault currents will be given in Section B of this chapter.

There are four possible types of faults: three-phase, double line-to-ground, line-to-line, and single line-to-ground. Three-phase faults can occur only on three-phase circuits, line-to-line and double line-to-ground faults can occur on three-phase or "vee"-phase circuits and line-to-ground faults can occur on any type circuit. Due to the multigrounded neutral construction of overhead lines, the line-to-ground fault is by far the most common, although other types do occur. For underground cables, the only type of fault that is likely to occur is a line-to-ground fault. However, the impedance of underground cable to three-phase and line-to-line faults is given in this bulletin because for combined underground-overhead lines, where the overhead section is farther from the substation than the underground cable, it is possible that a fault on the overhead line could cause either line-to-line or three-phase fault current to pass through the cable. The three-phase fault current generally determines the maximum fault current level for three-phase lines. Near the substation, however, it is possible that a line-to-ground fault may produce a larger fault current. This is because line-to-ground faults see a lower source impedance with a delta-

grounded wye transformer connection, but a higher impedance per kilometer of line than three-phase faults. Thus, to determine the maximum fault current on a three-phase line, it is necessary to calculate the line-to-ground fault current as well as the three-phase fault current up to that point on the line where the line-to-ground current becomes equal to or less than the three-phase current. (See Figure 1)

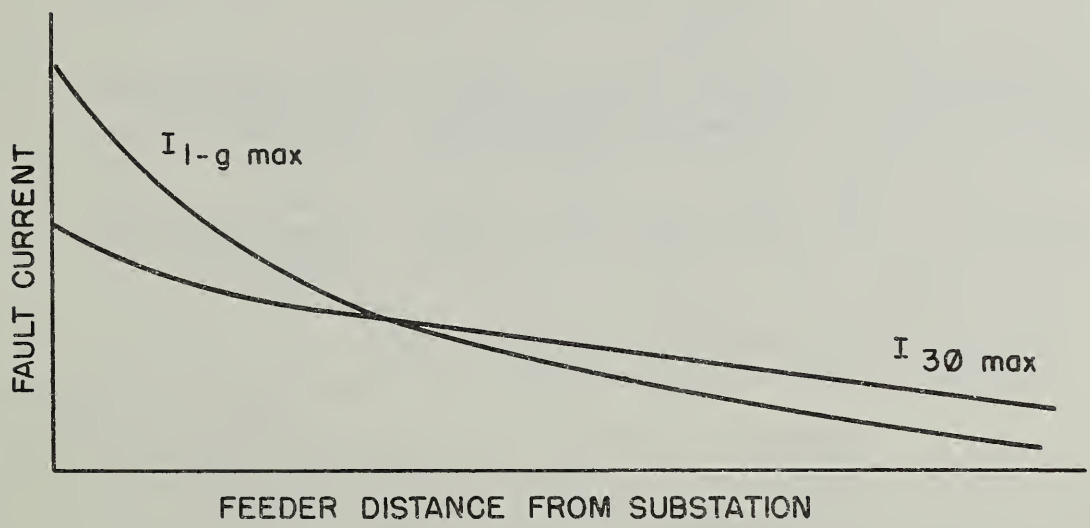


Figure 1 - Fault current on a distribution line supplied by a delta-grounded wye Substation transformer.

For "vee"-phase and single-phase lines, line-to-line and line-to-ground faults, respectively, yield the maximum fault current. Double line-to-ground faults usually yield neither a maximum nor a minimum value for any type of line and thus do not normally need to be calculated. See "Symmetrical Components" by Wagner and Evans[1] for further information.

Table IA summarizes for each type of line what type of fault will yield the maximum and minimum fault current values. The table is applicable for overhead, underground, and combined overhead-underground lines.

1 "Symmetrical Components," by Wagner & Evans, McGraw-Hill, 1933

TABLE IA

	Fault Type That Yields	
Line Type	Maximum Fault Current	Minimum Fault Current
Three-phase	Three-phase fault or line-to-ground fault near substation	Line-to-ground fault*
"Vee" or two-phase line	Line-to-line fault (Line-to-ground fault near a substation)	Line-to-ground fault*
Single-phase	Line-to-ground fault	Line-to-ground fault*

*A value for fault resistance must be included.

A calculation method for determining fault current will be presented in Section B of this chapter. Two graphical methods are also included in the appendix. Any of these three methods will yield comparable results.

B. Calculation Method for Determining Fault Currents:

1. General

Tables I through III (pages 18, 19, 20) contain the information necessary to calculate fault currents for line-to-ground (Table I), three-phase (Table II) and line-to-line (Table III) faults. In addition, Table IV (page 21) contains formulas that may be used in place of the standard source impedance formulas given in Part 1 of the first three tables when calculating the source impedance for a substation that is supplied by a small generating plant.

2. Use of Fault Current Calculation Tables

Regardless of the type of fault, there are three main components of the impedance offered to the fault: the impedance of the source, the impedance of the substation, and the impedance of the distribution line up to the location of the fault. For the minimum fault current, a fourth impedance, the fault resistance component is added. For most cases, the calculation of a fault

current consists of determining these three impedance components (four for minimum fault current), finding the total impedance offered to the fault and dividing the system line-to-ground voltage by this impedance. The steps below outline the procedure in detail and will be demonstrated in the sample problem in Chapter V.

a. Refer to the appropriate table for the type of fault for which values are to be calculated.

b. Depending on what information is given, use one of the equations in Section 1 of the table to find the source impedance. If the substation under consideration is fed from a small generating plant, the procedure outlined in Section 3 below and the information in Table IV can be used as an alternate method for determining source impedance. After the source impedance has been determined, it should be resolved into resistive and reactive components, either by using the formulas in the table or by taking a ratio based upon judgment and experience. Generally, the source impedance will be highly reactive.

c. Determine the substation transformer impedance in ohms by using the equation given in Section 2 of the table. As in b above, the impedance should be resolved into its reactive and resistive components either by using the formulas given in the table or by using a ratio based on judgment.

d. To find the distribution line impedance to any point on the system, multiply the appropriate value from Section 3 of the table by the number of kilometers of line from the substation to the point being considered. If two or more different sized conductors are used from the substation to the point, add the total resistance of the first size to the resistance of the next size to the point, and add the total reactance of the first size to the reactance of the next size, etc.

e. As indicated in Section 4 of the table, add up separately the resistance and reactance components determined in the steps above. (When calculating minimum line-to-ground fault current, be sure to include a fault resistance value.) Find the total impedance and divide the system line-to-ground voltage by this impedance value to determine fault current.

3. Determination of Source Impedance for Substations Fed by Small Generating Plants

The method presented in this section may be used when determining the source impedance for a distribution system supplied by a small isolated generating plant. The method is outlined below.

a. Turn to Table IV.

b. From Section 1 of Table IV, select the plant source impedance formula appropriate for the type of fault for which values are being calculated.

c. Using the formulas in Section 2 of Table IV, determine the particular reactance value in ohms (either transient) or negative sequence that are required by the formula selected in step b above.

d. Using the values calculated in c above and the formula selected in step b, calculate the plant source reactance and convert the resulting value to the distribution voltage by using the formula in Section 5 of Table IV.

e. Determine the resistance and reactance values per kilometer of tie line between the substation and generating plant. This can be done either by finding the appropriate values for the conductor size listed in Section 3 of Tables I, II, or III, (if the tie line is REA standard distribution line construction) or by using the impedance calculating formulas given in Appendix C of this bulletin. Refer to "Standard Handbook for Electrical Engineers"[1] or manufacturer's handbook for the data required in the formulas in Appendix C.

f. Multiply the value obtained in e above by the length of the tie line in kilometers and convert the resulting value to the distribution line voltage by using Section 5 of Table IV.

g. For any transformer in the tie line, determine the transformer impedance per phase by using the appropriate formula in Section 4 of Table IV and convert the resulting value to the distribution line voltage by multiplying by the factor given in Section 5 of Table IV.

h. Determine the total source impedance by adding vectorially the impedances of the plant, tie line and transformers in the tie line.

If machine reactances are not obtainable, the following values may be used for approximation. (To be used only with discretion.)

Slow speed diesel or reciprocating steam engine driven generators:

(1) Direct-axis transient reactance = 35%

(2) Negative sequence reactance = 22%

(3) Synchronous reactance = 110%

Non-salient pole turbine-driven generators:

(1) Direct-axis transient reactance

4 pole, 23% = 2 pole, 15%

(2) Negative sequence reactance

4 pole 16% = 2 pole, 11%

(3) Synchronous reactance can be neglected = 110%

[1]McGraw-Hill, Inc.

Machine resistance can be neglected.

Example: Determine the generator's impedance in ohms for a line-to-ground fault.

Generator: Slow speed diesel generator
1000 kV, Gen. output 2400Y/1386V

From the above table, the generator's characteristics are:

Direct-axis transient reactance	=	35%
Negative sequence reactance	=	22%
Synchronous reactance	=	110%

Refer to Table IV, page 21 for the calculations procedure and formulas.

Table IV 1,b,

Xgen = Xm (transient) + Xm (neg. seq.)

Xm (transient reactance) = $1/X_1$

$$X_1 = \frac{\% X_1}{(kVA_1)} \frac{(E_L)^2 (3)}{(100{,}000)} = \frac{(35)}{(1000)} \frac{(1386)^2 (3)}{(100{,}000)} = 2.017 \text{ ohms} = X_1$$

Xm (transient) = X_1 (ohms) = 2.017 ohms

$$\text{Xm (neg. seq.)} = \frac{(\%X_1)}{(kVA_1)} \frac{(E_L)^2 (3)}{(100{,}000)}$$

$$\text{Xm (neg. seq.)} = \frac{(22)}{(1000)} \frac{(1386)^2 (3)}{(100{,}000)} = 1.268 \text{ ohms}$$

$$\text{Xgen} = \frac{\text{Xm (transient)} + \text{Xm (neg. seq.)}}{3} = \frac{(2.017 + 1.268}{3}$$

Impedance of generator for line-grounds:

Xgen (ohms) = 1.095 ohms

Follow the same type of procedure for calculating the generator's impedance for line-to-line and three-phase faults.

4. Minimum Fault Current

It is necessary to calculate minimum fault currents for coordination purposes and also to define a maximum "reach" or zone of protection of an overcurrent protective device. To calculate minimum fault current, a value of fault resistance should be added to the resistance component of total system impedance up to the point of fault. The value of fault resistance is subject to judgment. The objective of selecting this resistance for calculation purposes is to make the probability of occurrence of faults with currents below this level as small as

possible, while recognizing that with simple overcurrent devices, such as fuses and single-phase reclosers, it is not possible to detect faults whose magnitudes are smaller than load currents. Yet, faults can occur which produce a value of current below peak load current. Therefore, it is evident that a dilemma is faced by a system protection engineer trying to provide sensitive overcurrent protection, yet not such sensitive protection that overcurrent devices will trip on load current. A value of 30 to 40 ohms is a reasonable resistance to select in minimum fault current calculations. Forty ohms is more conservative and is recommended for circuits from metering points, 24.9 kV distribution substations, and 12.5 kV distribution substations with transformer capacity of 5000 kVA and smaller. For circuits from 12.5 kV distribution substations rated larger than 5000 kVA, 30 ohms may be considered for use as the value of fault resistances to calculate minimum fault current. Regardless of the assumed value of fault resistance, it is desirable to choose reclosers which will detect 200 ampere (or lower) phase-to-ground faults.

On small systems supplied by isolated generation, the minimum fault current should be calculated by using the minimum number of machines which will be on line when calculating the source impedance. In addition, if the capacity of the plant is approximately the same as the demand on the distribution system (i.e., the plant serves little or no other load except the borrower), the positive sequence reactance used should be increased to allow for machine decrement. A value between the transient and the synchronous reactance may be used, the exact figure depending upon judgment. In most cases of this kind, a value of 40 percent is recommended for conservative results. For large machines, the impedance is small and the decrement is relatively unimportant.

For calculating minimum fault current on underground cable, the value of fault resistance is again a matter of judgment. Because of the proximity of the concentric neutral on direct buried cable, there is justification for assuming a lower fault resistance value than that assumed for overhead systems. A value of 10 to 20 ohms is reasonable.

5. Distribution Voltage Transformation

When a line is encountered that incorporates an autotransformer or two-winding transformer used for system voltage conversion (often 7.2 kV to 14.4 kV or vice versa), there are several additional steps that must be taken to find the fault current beyond these devices.

a. Using the procedure outlined in 2a through 2e in this chapter, determine the resistance and reactance values of the total impedance (source, substation transformer and distribution line) from the substation to the point on the line where

the step-up or step-down transformer is located.

b. Using the formula below, determine the impedance of the transformer in ohms.*

Two-winding transformer or autotransformer

$$Z_t \text{ ohms} = \frac{\% \quad Zt\ (EL)^2}{kVA\ 100{,}000}$$

Where EL is the line to neutral voltage on the load side of the transformer.

% Z_t is the percent impedance of the transformer given at rated kVA and voltage.

kVA is the kVA rating of the transformer.

Resolve the impedance into its reactive and resistive components, either by using the formula given below or by taking a ratio based on judgment.

$R_t = .2Z_t,\ X_t = .98Z_t$

c. Reflect the source, substation transformer and distribution line impedance (Z STD) determined in step a. to the load side of the voltage transformation transformer by the appropriate method shown below.

1. <u>Step-up transformation</u>

   Z STD load side ohms = (N^2) (Z STD source side ohms)

2. <u>Step-down transformation</u>

   Z STD load side ohms = $\left(\frac{1}{N^2}\right)$ (Z STD source side ohms)

Where $N = \frac{\text{high side line-neutral voltage}}{\text{low side line-neutral voltage}}$

d. Add the distribution line resistance and reactance values from voltage transformation transformer location to the location of the fault to the R and X values obtained in steps b and c.

R Total = R STD load side + R auto + R dist.

X Total = X STD load side + X auto + X dist.

e. Determine the fault current using the formula below and the R and X values determined in step d.

$$I_{fault} = \frac{E_{line\text{-}to\text{-}ground}\ (\text{load side voltage})}{\sqrt{(R_{total})^2 + (X_{total})^2}}$$

*For the purpose of this bulletin, it is assumed that only single-phase autotransformers or two-winding transformers will be encountered.

To find the fault current that would appear on the source side of the voltage transformation formula use the appropriate formula below:

1. <u>Step-down voltage transformation</u>

   Source side fault current = (1/N) (load side fault current)

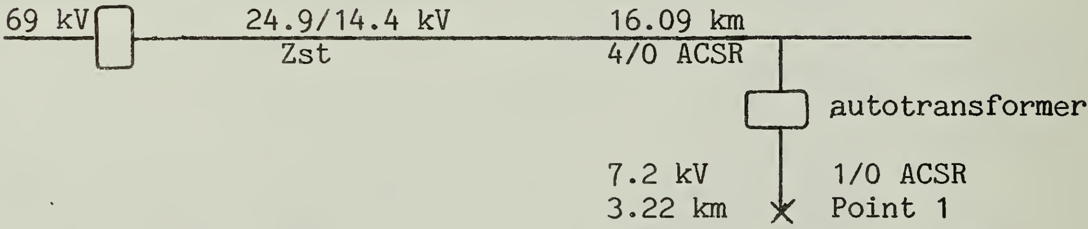
2. <u>Step-up voltage transformation</u>

   Source side fault current = (N) (Load side fault current)

Example: Determine the 3 phase fault current at point 1.

Step-down autotransformer, 200 kVA, 14.4 to 7.2 kV, %Z = 2.63

<u>Sample Problem</u>



Zdist = (.274 + j .442) (16.09) = 4.41 + j 7.12 ohms obtained from Table II.

Step a:

Zst	= 0 + j 3.6	given by supplier
Zdist	= 4.41 + j 7.12	
Zstd	= 4.41 + j10.72	

Step b:

$$\text{Zauto load side} = \frac{(\%\ Z)\ (E_L)^2}{(\text{kVA})\ \ (100{,}000)} = 6.82 \text{ ohms}$$

Rauto = (.2) (Zauto) = 1.36 ohms,

Xauto = (.98) (Zauto) = 6.68 ohms

Zauto = 1.36 + j 6.68 ohms

Step c:

$$\text{Z std loadside} = \frac{1}{N2}\ (4.41 + j\ 10.72) = 1.1 + j\ 2.68$$

Step d:

R dist = (3.22 km) (.550 ohms/km) = 1.77 ohms

Zauto = (3.22 km) (.470 ohms/km) = 1.51 ohms

$$Z\ std = 1.1 + j\ 2.68$$
$$Zauto = 1.36 + j\ 6.68$$
$$\underline{Zdist = 1.77 + j\ 1.51}$$
$$Z\ \ Total = 4.23 + j\ 10.87$$

Step e:

$$I\ 3\emptyset\ fault = \frac{7200}{\sqrt{(4.23)^2 + (10.87)^2}} = 617.3 \text{ amperes}$$

$I\ 3\emptyset = 617.3$ amperes

Conversely, the same procedure should be used if a step-up autotransformer or two-winding transformer should be used.

6. Fault Current on Supply Side

A fault anywhere on the load side of the substation causes a current to flow on the supply side. To determine the supply side current, use the following formulas.

a. For line-to-ground fault

$$I_s = \frac{E_L\ I_L^*}{E_s\ (L-L)}$$

b. For three-phase fault

$$I_s = \frac{E_L \sqrt{3}\ I_L}{E_s\ (L-L)}$$

c. For a line-to-line fault

$$I_s = \frac{2E_L\ I_L}{E_s\ (L-L)}$$

*Note: I_s is not necessarily the same in all three phases. The formulas give the maximum supply currents in any one phase.

7. Map Plotting

After the calculation of short circuit currents has been completed, these values should be placed on the circuit diagram at each sectionalizing point and at the end of lines.

Table I - Formulas and Information for the Calculation of Line To Ground Fault Current on Load Side of Substation

1. SOURCE IMPEDANCE (LOAD SIDE VOLTAGE BASE)

Type of fault current or impedance value given		Formula to determine source impedance (Z_s)
a. $I_{s(L-L)}$	line-line fault current on source side of substation	$Z_s = \dfrac{E_L^2}{I_{s(L-L)}\ E_{s(L-L)}}$
b. I_{3s}	Three-phase fault current on source side of substation	$Z_s = \left(\dfrac{2}{\sqrt{3}}\right)\left(\dfrac{E_L^2}{I_{3s}\ E_{s(L-L)}}\right)$
c. Z_1	Positive sequence impedance on source side of substation	$Z_s = 2Z_1\left(\dfrac{E_L}{E_{s(L-L)}}\right)^2$

Assume R_s (resistive component of source impedance) = 0, X_s (reactive) = Z_s or take an appropriate ratio between R_s and X_s based on judgment.

2. SUBSTATION TRANSFORMER IMPEDANCE

Formula to convert substation transformer impedance (Z_t) from percent to ohms

$$Z_t\,(\text{ohms}) = \frac{Z_t\ (\text{percent})\ E_L^2}{(\text{KVA per phase})(100{,}000)}$$

R_t (resistive component of substation transformer) = $.20Z_t$
X_t (reactive component of substation transformer) = $.98Z_t$
approximate

3. DISTRIBUTION LINE IMPEDANCE (SINGLE-PHASE IMPEDANCE VALUES)

Overhead Lines

ACSR Conductor Size	R_L in ohms per kilometer	X_L in ohms per kilometer
336.4 MCM	.255	.628
266.8 MCM	.317	.646
4/0	.398	.758
3/0	.472	.789
2/0	.584	.851
1/0	.696	.901
2	1.019	.913
4	1.535	.907
6	2.312	.957

Underground Cables

Aluminum Conductor Cable Size	R_L in ohms per kilometer	X_L in ohms per kilometer
350 MCM	.348	.099
250 MCM	.472	.131
4/0	.553	.162
3/0	.677	.2113
2/0	.820	.273
1/0	.969	.354
1	1.143	.435
2	1.342	.547

To convert to ohms per mile multiply ohms per kilometer value by 1.609

To obtain total distribution line resistance (R_{dist}) and reactance (X_{dist}) to any point, multiple appropriate value below by the number of kilometers of line. For two or more conductor sizes, calculate resistance and reactance values separately for each conductor size and total values for the sizes together.

4. CALCULATION OF FAULT CURRENT

$$I\left(\begin{array}{l}\text{maximum line to}\\ \text{ground fault current}\end{array}\right) = \frac{E_L}{\sqrt{(R_s + R_t + R_{dist})^2 + (X_s + X_t + X_{dist})^2}}$$

Symbols not defined above

E_L = line-to-ground voltage on load side of substation

$E_{s(L-L)}$ = line-to-line voltage on supply side of substation

Table II - Formulas and Information for the Calculation of Three Phase Fault Current on Load Side of Substation

1. SOURCE OF IMPEDANCE (LOAD SIDE VOLTAGE BASE)

Type of fault current or impedance value given		Formula to determine source impedance (Z_s)
a. $I_{s(L-L)}$	line-line fault current on source side of substation	$Z_s = \left(\frac{3}{2}\right)\left(\frac{E_L^2}{I_{s(L-L)}E_{s(L-L)}}\right)$
b. I_{3s}	Three-phase fault current on source side of substation	$Z_s = \sqrt{3}\left(\frac{E_L^2}{I_{3s}\ E_{s(L-L)}}\right)$
c. Z_1	Positive sequence impedance on source side of substation	$Z_s = 3Z_1\left(\frac{E_L}{E_{s(L-L)}}\right)^2$

Assume R_s (resistive component of source impedance) = 0, X_s (reactive) = Z_s or take an appropriate ratio between R_s and X_s based on judgment.

2. SUBSTATION TRANSFORMER IMPEDANCE

Formula to convert substation transformer impedance (Z_t) from percent to ohms

$$Z_t(\text{ohms}) = \frac{Z_t(\text{percent})\ E_L^2}{(\text{KVA per phase})(100{,}000)}$$

R_t (resistive component of substation transformer) = $.20Z_t$
X_t (reactive component of substation transformer) = $.98Z_t$
approximate

3. DISTRIBUTION LINE IMPEDANCE (THREE-PHASE IMPEDANCE VALUES)

Overhead Lines: ACSR Conductor Size	R_L in ohms per kilometer	X_L in ohms per kilometer	Underground Cables: Aluminum Conductor Cable Size	R_L in ohms per kilometer	X_L in ohms per kilometer
336.4 MCM	.173	.393	350 MCM	.185	.112
266.8 MCM	.218	.406	250 MCM	.255	.127
4/0	.274	.442	4/0	.300	.134
3/0	.346	.452	3/0	.367	.145
2/0	.436	.461	2/0	.466	.154
1/0	.550	.470	1/0	.675	.173
2	.876	.485	1	.722	.182
4	1.392	.500	2	.913	.191
6	2.181	.530			

To convert to ohms per mile multiply ohms per kilometer value by 1.609

To obtain total distribution line resistance (R_{dist}) and reactance (X_{dist}) to any point, multiple appropriate value below by the number of kilometers of line. For two or more conductor sizes, calculate resistance and reactance values separately for each conductor size and total values for the sizes together.

4. CALCULATION OF FAULT CURRENT

$$I\left(\begin{array}{l}\text{maximum three}\\ \text{phase fault current}\end{array}\right) = \frac{E_L}{\sqrt{(R_s+R_t+R_{dist})^2 + (X_s+X_t+X_{dist})^2}}$$

Symbols not defined above

E_L = line-to-ground voltage on load side of substation

$E_{s(L-L)}$ = line-to-line voltage on supply side of substation

Table III - Formulas and Information for the Calculation of Line To Line Fault Current on Load Side of Substation

1. SOURCE IMPEDANCE (LOAD SIDE VOLTAGE BASE)

Type of fault current or impedance value given	Formula to determine source impedance (Z_s)
a. $I_{s(L-L)}$ line-line fault current on source side of substation	$Z_s = \sqrt{3}\left(\frac{E_L^2}{I_{s(L-L)}\,E_{s(L-L)}}\right)$
b. I_{3s} Three-phase fault current on source side of substation	$Z_s = 2\left(\frac{E_L^2}{I_{3s}\,E_{s(L-L)}}\right)$
c. Z_1 Positive sequence impedance on source side of substation	$Z_s = 2\sqrt{3}\,Z_1\left(\frac{E_L}{E_{s(L-L)}}\right)^2$

Assume R_s (resistive component of source impedance) = 0, X_s (reactive) = Z_s or take an appropriate ratio between R_s and X_s based on judgment.

2. SUBSTATION TRANSFORMER IMPEDANCE

Formula to convert substation transformer impedance (Z_t) from percent to ohms

$$Z_t\text{(ohms)} = \left(\frac{2}{\sqrt{3}}\right)\left(\frac{Z_t\text{ (percent) } E_L^2}{\text{(KVA per phase)(100,000)}}\right)$$

$$\left.\begin{array}{l} R_t \text{ (resistive component of substation transformer)} = .20\,Z_t \\ X_t \text{ (reactive component of substation transformer)} = .98\,Z_t \end{array}\right\} \text{approximate}$$

3. DISTRIBUTION LINE IMPEDANCE (THREE-PHASE IMPEDANCE VALUES $\times\frac{2}{\sqrt{3}}$)

Overhead Lines

ACSR Conductor Size	R_L in ohms per mile	X_L in ohms per mile
336.4 MCM	.321	.731
266.8 MCM	.404	.754
4/0	.509	.822
3/0	.642	.841
2/0	.811	.857
1/0	1.02	.873
2	1.63	.901
4	2.59	.931
6	4.05	.985

Underground Cables

Aluminum Conductor Cable Size	R_L in ohms per mile	X_L in ohms per mile
350 MCM	.343	.208
250 MCM	.475	.236
4/0	.558	.248
3/0	.685	.270
2/0	.866	.286
1/0	1.07	.321
1	1.35	.338
2	1.70	.354

To convert to ohms per mile multiply ohms per kilometer value by 1.609

To obtain total distribution line resistance (R_{dist}) and reactance (X_{dist}) to any point, multiply appropriate value below by the number of miles of line. For two or more conductor sizes, calculate resistance and reactance values separately for each conductor size and total values for the sizes together.

4. CALCULATION OF FAULT CURRENT

$$I\left(\begin{array}{c}\text{maximum line to}\\ \text{line fault current}\end{array}\right) = \frac{E_L}{\sqrt{(R_s + R_t + R_{dist})^2 + (X_s + X_t + X_{dist})^2}}$$

Symbols not defined above

E_L = line-to-ground voltage on load side of substation

$E_{s(L-L)}$ = line-to-line voltage on supply side of substation

Table IV - Formulas for Calculating the Source Impedance for Substations Fed by Small Plants

1. Type of fault current to be calculated	Formulas to determine the machine impedance
a. 3-phase	Xgen = Xm (transient)
b. line-ground	$Xgen = \frac{Xm\ (transient) + Xm\ (neg.\ seq.)}{3}$
c. line-line	$Xgen = \frac{Xm\ (transient) + Xm\ (neg.\ seq.)}{\sqrt{3}}$
2. Formulas to determine machines transient and negative sequence reactance	
a. transient reactance	$X_1\ (ohms) = \frac{X_1 (Percent)\ (El)^2\ (3)}{kVA_1\ (100{,}000)}$ X_1 = direct-axis transient reactance for maximum fault current X_2 and X_3 can be found in a similar manner Then, $\frac{1}{X_m} = \frac{1}{X_1} + \frac{1}{X_2} + \frac{1}{X_3} + \ldots$ If all machines are alike $X_m = X_1$(n should be maximum for max. fault current)
b. negative sequence reactance	Xm (neg. seq.) is calculated by using the formulas in section 2a. Where the X_1, X_2, X_3 ... (Percent) values are the machines negative sequence reactance
3. Type of fault current to be calculated	Formulas for calculating the impedance of the tie line
a. line-ground	$Z\ tie\ line = (2)(Z_1) = (2)(R_1 + jX_1)$ R_1 = positive sequence resistance of tie line ohms/km X_1 = positive sequence impedance of tie line ohms/km Z_1 = positive sequence reactance of tie line ohms/km
b. 3-phase	$Z\ tie\ line = (3)(Z_1) = (3)(R_1 + jX_1)$
c. line-line	$Z\ tie\ line = (2)\ (\sqrt{3})(Z_1) = (2)(\sqrt{3})\ (R_1 + jX_1)$
4. Type of fault current to be calculated	Formula to calculate the impedance of any transformer in the tie line
a. line-ground	$Z\ tie\ line\ (ohms) = \frac{(2)(Z_1\ (Percent\ ))(El^2)}{(3)\ kVA/phase\ (100{,}000)}$
b. 3-phase	$Z\ tie\ line\ (ohms) = \frac{Z_1\ \ (Percent)(El^2)}{(kVA/phase)(100{,}000)}$
c. line-line	$Z\ tie\ line\ (ohms) = \frac{(2)Z_1(Percent)(El^2)}{(\sqrt{3})(kVA/phase)(100{,}000)}$
5. Formula to convert impedance to distribution voltage level Multiply impedance by $\frac{El^2}{E_s(1-1)}$	

CHAPTER III

TYPES OF SECTIONALIZING DEVICES

Apparatus which can be used for overcurrent protection and sectionalizing includes circuit breakers, reclosers, sectionalizers, fuse cutouts, current limiting fuses, power fuses, and circuit switchers. These devices will operate to automatically open the circuit in the event of a system fault condition.

Other useful sectionalizing equipment includes disconnect switches of all types. These are usually non-automatic devices but they can prove very effective in operating a distribution system. They can function to improve service reliability by reducing the search and location time of hidden faults and by limiting the effects of faults of long duration to the minimum number of consumers.

A. Circuit Breakers

Circuit breakers can have vacuum, oil, SF_6 gas or air as an interrupting medium. They are used where the power supplier requires them or when the circuit voltage or fault current exceeds the ratings of automatic circuit reclosers. When used for distribution feeder protection, they are normally controlled by time-overcurrent relays and reclosing relays. When used as the high side protective device for substation transformers, they are generally tripped by differential relays, sudden pressure relays, and/or overcurrent relays. They may sometimes be remotely tripped by the subtransmission relaying system by pilot wire, powerline carrier, or microwave communication channels. In general, circuit breakers and their relaying are more expensive than reclosers. However, the total installed cost of some non-series-coil three-phase reclosers can approach the total installed cost of some circuit breakers with relays. Circuit breakers require an external source of closing energy and normally require a dc source for tripping. They can also be used with a capacitor trip device.

B. Automatic Circuit Reclosers

Automatic circuit reclosers have been sucessfully used on rural circuits for many years. Reclosers are available with a wide range of current and voltage ratings and are suitable for use on virtually all distribution circuits.

The original concept of reclosers was to provide a self-contained, low cost, tripping and reclosing circuit interrupter which could be used economically for pole mounted protection of distribution feeders. This type of recloser is what is presently defined by standards as "series-coil" reclosers. These employ a series trip coil which causes tripping of the recloser at approximately two times the continuous current rating of the coil. These can be either single-phase or three-phase devices. They may employ either

a hydraulic timing mechanism for time delayed operating curves or may feature a hold-closed method of operation after the fast curve (instantaneous trip) operations. In some of the heavy duty three-phase or single-phase models, they may use a closing solenoid connected between phases or phase to neutral. Series-coil reclosers are used in both substation and line applications.

The concept of reclosers has been extended in recent years to include three-phase reclosers whose application, in many respects, resembles the application of power circuit breakers. This type of recloser is defined by standards as "non-series-coil" reclosers. These employ either time-overcurrent and reclosing relays or solid-state control devices in order to provide the time-current tripping operations, reclosing and resetting functions, and lockout provisions. Non-series-coil reclosers require a source of tripping energy other than line current. In the case of solid-state controls, this is usually a self-contained battery, or in the case of a relay-controlled recloser, it is frequently a station battery source. Some non-series-coil reclosers also require an external source of energy for the closing mechanism. Non-series-coil reclosers are applied mainly in substations or at metering points on rural distribution circuits, although occasionally they are used in line applications.

C. Automatic Line Sectionalizers

An automatic line sectionalizer is an oil, air, or vacuum switch which automatically opens to isolate a faulted section of line. It employs either a hydraulic or electronic counting mechanism which is actuated by a system overcurrent and a circuit breaker or recloser tripping action. Unlike other overcurrent protective devices, a sectionalizer does not operate on a time-current curve.

Automatic line sectionalizers are used principally in branch circuits where:

1. Small loads or little circuit exposure will not justify reclosers.

2. It is desirable to establish an automatic sectionalizing point but where time-current curve coordination with other sectionalizing devices would be difficult or impossible.

Automatic line sectionalizers are available as either three-phase or single-phase devices. They are not rated to interrupt fault current and, therefore, must be used in conjunction with backup reclosers or circuit breakers capable of sensing and interrupting minimum fault currents beyond the sectionalizer. The recloser or circuit breaker must sense a fault and perform the circuit tripping and fault clearing operation. The function of the sectionalizer is to count the number of recloser or breaker trips. After one, two,

or three trips, depending upon its setting, the sectionalizer automatically locks open during the open circuit time of the breaker or recloser. A sectionalizer may be used for switching loads within its load interrupting rating.

D. Fused Cutouts

Fused cutouts can play an important part in sectionalizing a distribution circuit. Properly coordinated with backup reclosers, fuses can help reduce the total cost of sectionalizing equipment without reducing service reliability or increasing operation and maintenance expense. Their use is recommended in combination with automatic circuit reclosers as described later in the bulletin.

E. Distribution Current Limiting Fuses (CLF)

Current limiting fuses are relatively expensive when compared with expulsion fused cutouts. They are also more difficult to apply since one must consider not only their continuous current rating, but also their maximum (and sometimes minimum) voltage rating and their ability to interrupt a current in less than one-half cycle. Industry standards define both "general purpose" and "backup" current limiting fuses. In general, where current limiting fuses are being considered, the backup type will usually prove more desirable than general purpose type unless the general purpose fuses have time-current curves which nearly parallel expulsion fuses. The advantage of backup current limiting fuses are:

1. No change in existing fusing principles or methods are required for coordination.

2. The majority of faults will blow only the expulsion fuse which is chosen to coordinate with the current limiting fuse.

The disadvantage of backup current limiting fuses is:

1. It must be used with a coordinated expulsion fuse. If an expulsion fuse larger than the one for which the CLF has been designed to coordinate is employed, the CLF may attempt to interrupt a current below its ability to clear, resulting in a burned up fuse and a likely system fault.

Current limiting fuses, even though they are expensive, can often be justified for:

1. Fusing distribution transformers on overhead circuits where available fault current is high. Engineering judgment is required in this regard because the probability of disruptive transformer failure is related not only to the available fault current, but also to the rated interrupting current of a transformer internal under-oil expulsion fuse and/or the tank pressure withstand ability.

2. Fusing underground cables and associated equipment. In the case of underground equipment, current limiting fuses may be justified even where fault current is not high. Since a CLF operates without expulsion action, it can be placed in a confined space. For underground applications, either a general purpose or a backup CLF with an under-oil expulsion link can be employed successfully.

F. Power Fuses

Power fuses can be either current limiting, conventional expulsion, or boric acid type of fuses. They have higher interruptive ratings than distribution fused cutouts and are, therefore, seldom applied on distribution circuits unless the available fault current is extremely high. Power fuses find their largest application as transformer bank protection or the "high-side fuse" for relatively small distribution substation transformers. They usually have a maximum voltage rating of 138 kV and the fuse links are generally "E" rated.*

G. Circuit Switchers

A circuit switcher is a high voltage load switching and fault interrupting device which usually, but not always, incorporates a disconnect switch function in the switching operation. Voltage ratings are usually in the range of 69 kV through 161 kV, although this range may be extended in the future. It should be recognized that a circuit switcher is not a circuit breaker. It has a fault interrupting rating less than the smallest standard rating for circuit breakers and it does not have high speed reclosing ability. A further limitation is that there are no provisions for mounting current transformers.

Even though a circuit switcher has some limitations, it is well suited for protection of substation transformers against secondary and internal faults, switching transformer magnetizing current, load dropping, capacitor bank switching, cable switching, and switching both series and shunt reactors. It is finding application for sectionalizing transmissions and subtransmission circuits where high speed reclosing is not required and where fault duties are modest.

A circuit switcher can represent a considerable cost saving over a circuit breaker and is frequently a good economical choice where a transmission voltage fault interrupter is required.

*"E" rated is an industry standard rating for power fuses which prescribes standardization for fuse melting current at 300 seconds.

CHAPTER IV

SELECTING THE RATINGS OR SETTINGS OF SECTIONALIZING DEVICES

A. General Requirements For Substation Overcurrent Protection

Assuming that automatic circuit reclosers will be used on the distribution side of the substation, it will be necessary to determine the rating of the recloser(s). The basic function of the recloser is to protect the substation equipment (transformers, regulators, buswork) and the distribution conductors, up to the first line sectionalizing device, from thermal damage due to fault current. Mechanical damage to transformers due to through-fault current can occur during the first cycle or two of fault current. Therefore, overcurrent protective devices cannot be relied upon to prevent this type of damage. The protection afforded to transformers by the reclosers can be checked by comparing the total opening time (cumulative time-current curve) with the damage time curve of the transformer for the range of fault currents in the section controlled by the reclosers.

Adequate consideration should be given to the protection of the distribution system conductors from thermal damage due to fault current. This applies to both overhead conductors and underground cable. If reduced neutral concentric neutral cable is being used, the ability of the neutral conductor to carry the available fault current without damage to the cable insulation or semi-conducting shield is the controlling factor.

The following factors should be considered in selecting the substation reclosers:

1. Maximum Fault Current

   The recloser must be rated to interrupt the maximum fault current at the substation. Some margin should be allowed above this value because the trend is toward higher fault currents in the future as changes are made and additional capacity is added to the power supply system.

2. Maximum Load Current

   Load growth should be considered in selecting the recloser size. A practical growth limit might be that which would require changes in either the conductor or substation transformers. Related to load and load growth is inrush current following an outage and is commonly referred to as "cold load pickup." The lower the load current is in relation to the recloser continuous current rating or trip setting, the less likely will be the problem of tripping on cold load following an outage. Ideally, the load current should be kept at 70 percent or less of the recloser rating.

However, practical considerations frequently dictate that reclosers be operated near or at their continuous current rating. In these situations, manual sectionalizing of the circuit may have to be performed in order to successfully reenergize a fully loaded circuit after an extended outage.

3. Type Load Being Served

The type of load being served by small rural substations is usually predominantly single phase. In these cases, single-phase reclosers inherently provide the best service reliability to consumers. However, if feeder loads are predominantly three-phase loads, such as industrial or commercial areas, irrigation pumps, or oil well pumps, three-phase reclosers should be considered for use.

If there is three-phase load connected to an underground cable circuit which has the transformer bank connected other than grounded-wye, grounded-wye a three-phase recloser at the substation (and other sectionalizing points) is recommended. Three-phase sectionalizing devices will minimize the probability of occurrence of ferro-resonance* in three-phase underground primary systems.

4. Minimum Fault Current

The minimum fault current at the end of the feeder section protected by the substation recloser determines the minimum trip requirements and, consequently, the series trip coil rating or trip setting of reclosers. If 40 ohms fault resistance is used for fault current calculations, the minimum fault current will be less than 180 amperes. Therefore, a 70-ampere series coil recloser will be the maximum size which will detect a calculated minimum line-to-ground fault.

If 30 ohms fault resistance is used in calculations, the minimum fault current will not exceed 240 amperes. In this case, series trip reclosers should not exceed 100 amperes.

If a feeder load exceeds 2000 kVA at 12.5 kV or 4000 kVA at 24.9 kV (approximately 100 amperes), it will be necessary to use a non-series coil recloser, relayed power circuit breaker, or three-phase series coil recloser with a ground trip accessory. With these circuits designed to carry heavy loads, phase trip settings should not exceed 200 amperes unless ground-tripping is used. The ground trip setting should be set as sensitive as practical and not to exceed 200 amperes.

5. Substation Transformer Protection

The substation transformer should be protected from thermal damage

*See REA Bulletin 61-3, "Underground Rural Distribution" for additional information about ferro-resonance

due to distribution system short circuits. This should be assured by comparing the transformer damage curve with the overcurrent protective device time current curves. It is generally not possible for high side overcurrent relays or fuses to protect substation transformers from short time overloads. To attempt to do so would increase the risk of tripping the circuit on inrush currents and would also severely limit the full load kVA capability of the transformer. If overload protection is to be afforded, it should be done with thermal devices built into the transformer or by the distribution feeder overcurrent protective devices. Occasionally, it may be difficult to provide transformer overload protection with the feeder reclosers and still obtain the satisfactory number of line protective devices. In these cases, a circuit breaker or recloser can be located on the transformer low voltage bus (see Figure 2). This is not encouraged unless absolutely necessary because of the added expense.

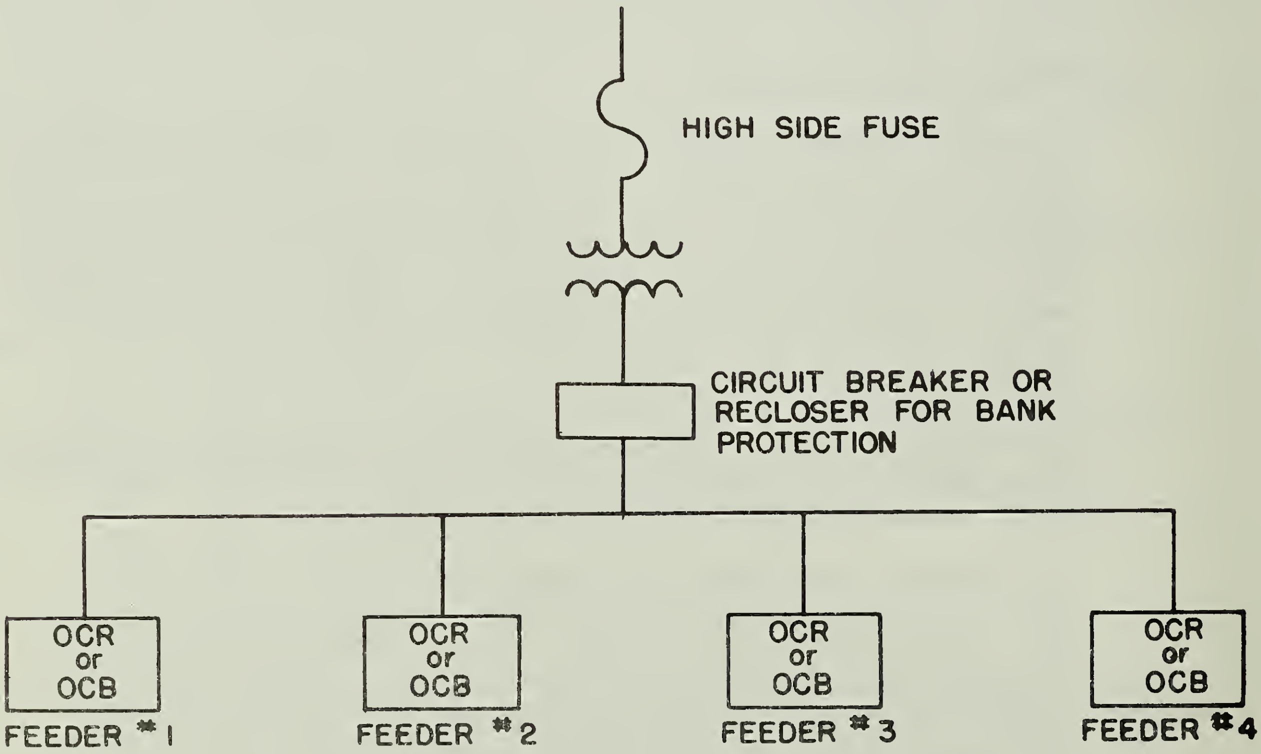


Figure 2 - Bank breaker scheme for protection of substation transformers.

The transformer damage curves, Figures 26 and 27, in Appendix E, may be used if no exact information about the transformer is available. For transformers larger than shown on the curves, the curves from ANSI C57.92 shown in Figure 28 of Appendix E, may be used to construct a transformer damage curve.

6. Substation Protection - High Voltage Side

The high side protection of substation transformers is provided most economically by power fuses. These should normally be used for substation transformers rated 12/16/20 MVA and below with transmission voltages 138 kV and below. The decision concerning high side protection should be based upon transmission line relaying considerations and, therefore, may be dictated by the power supplier. It is beyond the scope of this bulletin to detail all the various transmission protection requirements and methods. However, substation transformers rated higher than 20 MVA represent a considerable investment and consideration should be given to protecting the transformer from excessive damage due to an internal fault or low voltage bus fault. If an internal transformer fault can be tripped fast enough, it may be possible to prevent excessive internal damage. In order to provide this type protection, a high side switching device can be installed and tripped by one or more of the following: (See Figure 3)

a. Sudden pressure relays.

b. Differential relays.

c. Overcurrent relays.

d. Fault gas monitor relays.

If any of these relays is being applied, the power transformers and/or power circuit breakers should be purchased with the necessary multi-ratio current transformers factory installed. In the case of the sudden pressure relay, the pressure sensitive switch (actually sensitive to rate of change of pressure) should be specified as an accessory to a new transformer.

The high side switching devices may be:

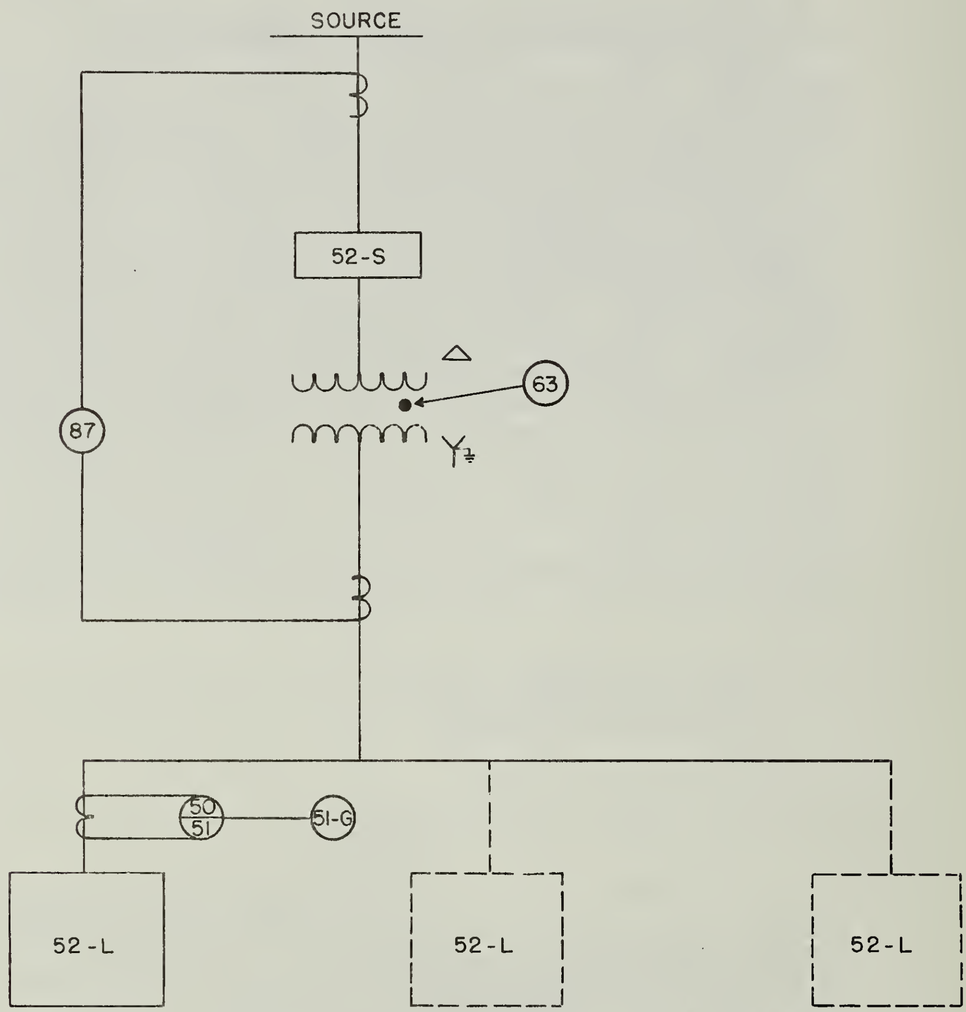
a. High speed grounding switches in conjunction with motor operated air break switches.

b. Circuit switchers, provided the switchers are rated to interrupt the available fault current.

c. Circuit breakers.

Circuit switchers are sometimes applied where fault duty is above the switchers rating, provided the device is blocked for all faults above the rating and provided carrier relaying or other high-speed relays will operate for fault currents in excess of the rating.

This, of course, requires close coordination and cooperation between a distribution borrower and the power supplier. It should be emphasized that all high-side protection should be approved by the power supplier.



52-S - SOURCE BREAKER, OR CIRCUIT SWITCHER, OR M.O. AIR BREAK SW/ GROUNDING SW

52-L - FEEDER BREAKER WITH OVERCURRENT RELAY, OR NON-SERIES COIL RECLOSER, OR SERIES COIL RECLOSER

87 - DIFFERENTIAL RELAY

63 - SUDDEN PRESSURE RELAY

50 - INSTANTANEOUS OVERCURRENT RELAY

51 - TIME OVERCURRENT RELAY

51-G - GROUND TIME OVERCURRENT RELAY

Figure 3. Relay schemes for protection of substation transformers.

7. Conductor Damage Curve

Conductors can be heated by fault current to the point of annealing (or in extreme cases conductor melting) which can reduce the conductor strength to the point where line tension causes the conductor to break. It is recommended that the annealing or burndown characteristics of the conductor (refer to Appendix F) in the controlled section of line be coordinated with the recloser time-current curves. The recloser time-delay curve plus 10 percent tolerance should not exceed 75 percent of the annealing time of the conductor. This is usually most critical at the maximum available current but should be compared throughout the fault current range. The damage time of concentric neutral underground cable (Figure 33, Appendix F), especially where reduced neutral is being employed, should be considered and compared with the clearing curve of the recloser or power circuit breaker. If automatic reclosing is employed, comparing the cumulative clearing curve of the recloser or breaker relays with the damage curve of the cable is a conservative method. Some allowance can be made for cable cooling if reclosing intervals are long.

B. General Requirements for Overhead Distribution Line Sectionalizing

It is necessary to determine the maximum fault current, maximum load current, and minimum fault current at each sectionalizing device location on the distribution feeder. It is also necessary to determine the minimum fault current at the ends of all circuits and branch lines.

The objective of line sectionalizing is to economically minimize the number, duration, and extent of interruptions of consumer service while protecting line equipment and conductors from damage due to through fault current. This is accomplished by selecting and locating the most cost effective sectionalizing devices at strategic locations on the circuit in a manner that will give complete circuit protection for both temporary and permanent faults. The objective is accomplished by coordinating the sectionalizing devices such that only the source side device closest to the fault will lock out that portion of the circuit for a permanent fault.

1. Recloser-Recloser Coordination

The simplest method of coordinating reclosers in series is to choose the same make and style number of recloser and then to select reclosers in descending coil sizes. Usually, adjacent coil sizes will coordinate satisfactorily if the reclosers are not spaced too closely. However, if load current or fault current at the substation is high, it may be uneconomical to use the higher interrupting rated recloser throughout the entire circuit. When reclosers of different make or type are used in series, it will be necessary to plot the time-current characteristic (TCC) curves of each recloser in order to determine coordination.

Coordination by merely selecting adjacent coil sizes can frequently be achieved with series coil reclosers of different make or type. However, this should be checked by comparing TCC curves. The fast curves may have different slopes and speeds but in most cases it is usually not possible to coordinate fast curves on series coil reclosers.

It is possible to coordinate series reclosers by selecting different time delay operating curves or number of operating sequences. This generally is not recommended, however, except in special cases where coordination cannot be achieved otherwise. It is good practice to standardize on a particular time-delay curve and operating sequence for all line reclosers on a system. (This does not necessarily apply to substation reclosers. The demanding requirement of substation protection and coordination can often be met by special selection of curves and sequences for each station or feeder.) Experience has indicated that a sequence of two fast curve operations followed by two time delay curve operations followed by lock-out is a good choice for line reclosers. However, some system operators may wish to standardize on one fast and either two or three time-delay curves. In high lightning incidence areas it may be advantageous to use three fast curves followed by a time-delay curve.

When either (or both) recloser in series is a nonseries coil recloser, there is a wide variety of settings which is possible to make. In addition to a large number of time-current curves from which to choose, there are also a number of reclosing intervals, resetting intervals and minimum trip levels available. Since there is no series trip coil, the minimum trip can be selected without regard for coil size. Numerous accessory circuits are available which have been developed to achieve certain coordination features. It is recommended that an engineer specifying nonseries coil reclosers for use on an REA borrower's system become thoroughly familiar with the principles of operation of either the relays or electronic controls and with the mechanical operation of the interrupter mechanism. There is considerable expertise required in applying these devices and their accessories. Nonseries coil reclosers, properly applied, can prove extremely valuable in solving coordination problems. However, if misapplied, certain accessory features, or even standard features, may create more operating problems than those thought to have been solved.

One commonly overlooked characteristic of nonseries coil reclosers is the control response curve associated with each clearing curve. It should be understood that when the control response curve of an electronic control is exceeded, the interrupter has been committed to trip, regardless of the total clearing curve. Thus, control response curves of both fast (instantaneous) and time-delay curves should be compared with load side sectionalizing device operating curves. As an example, the control response curve,

including tolerance, of the time delay curve must lie above the maximum clearing curve, including tolerance, of a load-side recloser or fuse if coordination is required.

Reclosing intervals and resetting intervals may require coordination with other devices when applying nonseries coil reclosers. It is also important to consider that nonseries coil reclosers require a source of power for closing. This can be a high voltage or low voltage closing coil or an AC or DC motor. Correct closing power specifications must be provided and the operating personnel should be reminded that the device will not operate properly on any other voltage without major modification.

With either a series coil or nonseries coil recloser, consideration should be given to the curve tolerances when coordinating reclosers in series. There is usually a $\pm$ 10 percent tolerance on the time delay-curves, although there is normally no plus tolerance on the fast curve. As a general guide the following separation of time for a given current will determine coordination. If curves are separated by 0 to 2 cycles, there will be simultaneous operation (no coordination). If curves are separated by 2 to 12 cycles, there may or may not be simultaneous operation. To insure coordination, more than 12 cycles should be allowed between curves. A nonseries coil recloser can sometimes be coordinated if its curve is separated from another recloser curve by less than 12 cycles.

Each recloser should be checked to insure that its rating is adequate for load and fault current at the point of installation. A check should be made to determine that the minimum fault current at the next load side (down line) sectionalizing device is high enough to trip the source side recloser. Some relocation of a recloser from its tentative location may be necessary in order to bring currents within the recloser rating. On branch circuits or taps it may be desirable to reduce by two coil sizes a recloser rating where possible since this will insure better coordination.

For all recloser applications, care must be taken to insure that the following conditions are met:

a. The recloser must have a voltage rating equal to or greater than the system voltage. Recloser ratings are based upon line-to-line (system) voltage. Therefore, single-phase reclosers with a rating of 14.4 kV should not be applied on three-phase or single-phase lines of 24.9/14.4 kV. All reclosers used on 24.9/14.4 kV systems should have 24.9 kV on the nameplate.

b. The recloser must have an interrupting rating equal to or greater than the maximum available fault current at the point of application. The closer an installation is to the substation, the less desirable it is to install a recloser whose rating is at or near the system maximum fault current.

c. The recloser continuous current rating (for series coil reclosers, this is the coil size) must be equal to or greater than the peak load current at the point of application. The closer an installation is to the substation, the less desirable it is to install a recloser whose coil rating is at or near the peak load current.

d. The recloser minimum trip (usually twice coil rating for series coil reclosers) must be equal to or less than the minimum fault current within the zone to be protected by the recloser. If load current requires a series coil recloser greater than 100 amperes, consideration should be given to using a three-phase recloser with ground sensing set no higher than 200 amperes. A nonseries coil recloser will detect a 200 ampere phase-to-ground fault if its phase trip setting is 200 amperes or less. Even at 24.9/14.4 kV it is considered good operating practice to detect and trip for 200 ampere or lower phase-to-ground faults at all recloser installations.

e. The recloser must be selected (set) in a manner which will allow it to coordinate with other overcurrent protective devices on both the load and source side.

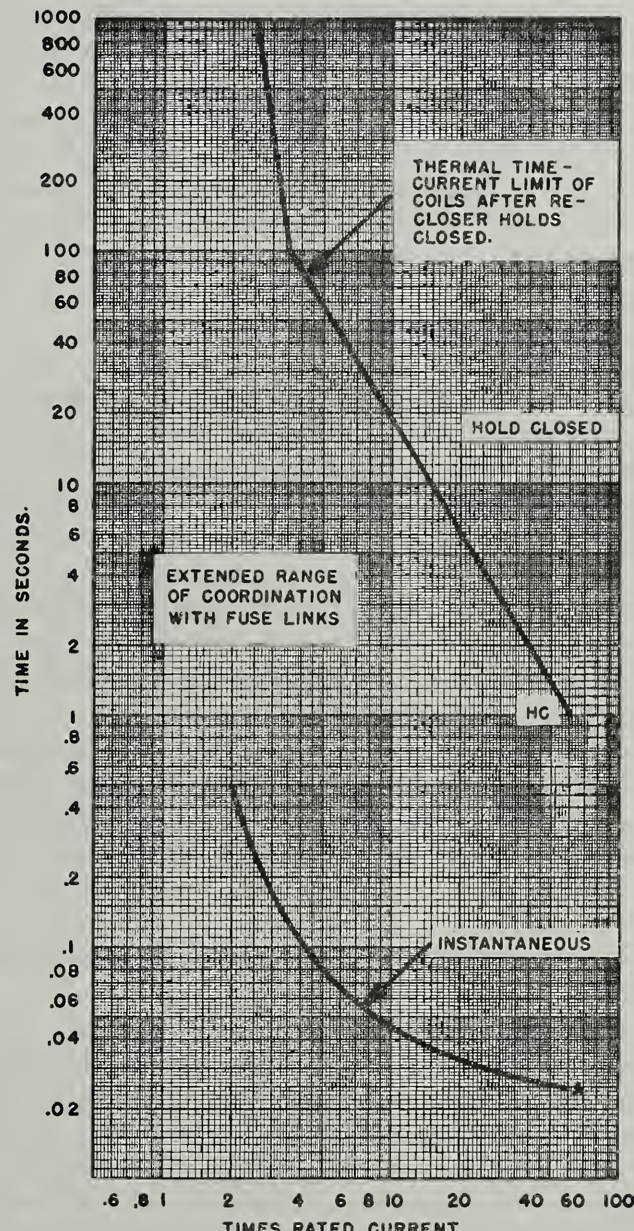
2. Recloser-Fuse Coordination

Coordination of reclosers with fuses is similar to coordination of reclosers in series. However, the purpose of this coordination is to permit the recloser to clear all temporary faults beyond the fuse and to force the fuse to blow on permanent faults. Coordination is determined by plotting the time-current curves of both the recloser and fuse. If the recloser sequence is two fast, followed by two delayed operations, the recloser fast clearing curve should be multiplied by a factor of 1.5 to take into account the accumulation of heat in the fuse during both fast-curve operations. If only one fast curve is used on the recloser, no multiplying factor need be used. The fuse curves, both minimum melt and maximum clearing curves, should be plotted. The fuse curves should lie between the fast curve and the time delay curve over all or most of the range of available fault current. Tolerance should be allowed for recloser time delay curves. Control response of the fast and time-delay curves should be used if the recloser is the nonseries coil type. Due to the shape of the curves, it may not be possible to achieve perfect coordination over the entire fault current range. In general, EEI-NEMA Type T fuse links provide the widest range of coordination with reclosers.

It is desirable to employ recloser fuse combinations which will allow the recloser to sense a minimum calculated fault at the end of the line. However, if this is not practical, the fuse should melt for an end-of-the-line minimum fault in approximately 20 seconds or less.

Some protection engineers and operating personnel prefer to coordinate a circuit with "hold-closed" series coil reclosers rather than with "lock-open" series coil reclosers. A hold-closed recloser trips two times on its fast (instantaneous) curve and then locks in the closed position. With this over-current protection concept, the recloser trips fast to provide

200 Ampere Frame Size



Time-current Curve for Hold-closed Reclosers

Figure 4

protection to the line for non-persistent faults, while a fuse, either at or near the recloser location, or at a down line location, clears the circuit for a persistent fault. The recloser then resets automatically. An advantage of the hold-closed recloser method of sectionalizing is that a larger number of fuse sizes over a wider range of fault current can be coordinated with a hold-closed recloser. Coordination of sectionalizing points on an entire circuit is simplified because it becomes a matter of merely coordinating fuses. Another advantage which could reduce maintenance expense is the fact that hold-closed reclosers will trip only twice for persistent faults. This should reduce recloser maintenance by 25 to 50 percent.

Figure 4 shows a typical hold-closed recloser time current curve. The upper curve is the thermal time-current limit of the series trip coil. Fuse link curves should be coordinated between the instantaneous curve and the thermal limit curve.

3. Fuse Link - Fuse Link Coordination

Many branch lines can be most economically protected by fused cutouts. It is desirable that they be coordinated with and protected by reclosers as previously described. It is sometimes practical to apply in series two fuse links with different ratings protected by one recloser.

At other locations, it may be more economical to provide only permanent fault protection by coordinating fuse links in series. It is best to limit the number of branch line sectionalizing fuses in series to two or three.

It is recommended that the same make or type fuse link be used throughout a system. The EEI-NEMA Type K or T links are preferable since they are standardized and are available from several suppliers.

When coordinating sectionalizing line fuses in series, the following factors should be considered:

a. Peak load currents at the point of application should be less than the fuse link rating. The fuse link must be large enough to withstand inrush currents to motors, capacitor banks, and transformer banks. In addition to these transients which last only a few cycles, consideration should be given to cold-load pickup which can last several seconds to several minutes. An EEI-NEMA Type K or T link with a tin fusible element can be considered to have a continuous current rating of 150 percent of its nominal current rating. All other links should be considered to be 100 percent rated.

b. The fuses should be coordinated with each other by applying the 75 percent rule. This means that the load-side fuse maximum clearing curve should not exceed 75 percent of the source side fuse minimum melting curve.

c. The fuse link(s) should be coordinated with the burndown characteristic of the conductors in the fuse zone of protection. Refer to Appendix F.

d. A fuse link should melt in approximately 20 seconds or faster for a minimum fault in its zone of protection.

C. General Requirements for Underground Line Sectionalizing

1. Total Underground Circuit Sectionalizing

If a circuit is completely underground, it should be assumed that there can be no temporary faults on that circuit. Therefore, there is no justification for automatic reclosing overcurrent protective devices for the purpose of clearing temporary faults. An all-fuse sectionalizing plan can be considered, provided selective coordination of fuses in series can be attained. If ferroresonance is anticipated, or if single phasing of three-phase loads would be a problem, nonreclosing, three-phase fault interrupters can be used if coordination can be achieved between devices. A combination of fuses and fault interrupters is certainly a possibility for an all-underground sectionalizing plan.

If coordination between one-shot devices cannot be assured due to load current or fault current conditions, automatic reclosing circuit interrupters (reclosers) and fault counting devices such as sectionalizers may be considered. In this case, the reclosers would not be used for the purpose of clearing temporary faults, but instead would be used to assure selective coordination of sectionalizing devices. While it is true that reclosing on an underground fault can exacerbate the damage to a faulted cable and can conceivably damage a sound adjacent cable, it is felt that an overriding consideration is to selectively sectionalize the smallest section of cable, thereby rendering better service to consumers. The general rule-of-thumb is that it is not necessary to reclose on an underground fault. However, if in the judgment of the engineer, better service reliability to the most consumers can be expected by choosing an automatic reclosing device, it is preferable to do so. The number of reclosing operations should be held to a minimum. Usually one reclosing, or at most two reclosings, will be all that will be required for coordination with other devices.

2. Overhead-Underground Circuits

Circuits with both overhead and underground construction present different sectionalizing problems than either a total underground circuit or a completely overhead circuit. It is not unusual for circuits to exit from a distribution substation with underground

cable. The underground exit may extend for several hundred meters or for several kilometers before it reaches an overhead transition point. Overhead distribution circuits can also dip underground at any point and re-emerge again to continue as an overhead line. Considerable engineering judgment should be exercised in selecting sectionalizing devices for these combination lines. If the majority of the line is underground with a small percentage overhead, the line can be considered similar to an all underground circuit. The converse is also true. If the line is predominately overhead with a small part of it underground, it can be considered as a completely overhead system when choosing overcurrent protective devices.

It is usually not possible to install fuses between reclosers, although it may seem desirable to do so on certain overhead, underground circuits. An attempt to do this usually results in fuses and reclosers being larger than would ordinarily be selected. This, in turn, results in the entire coordination of time-current curves back to the substation being undesirably high.

A three-phase automatic line sectionalizer can be installed between three-phase reclosers provided the sectionalizer is equipped with the sensing required to permit it to count only the backup recloser operations. This is sometimes described as voltage restraint. The advantage of a sectionalizer is that it does not operate on a time-current curve. The disadvantage of the sectionalizer is that it would probably be set for one count and is, therefore, a high-cost device as compared to a fuse.

If the expense of three-phase sectionalizers and three-phase reclosers cannot be justified, the alternate is to treat the underground section of line as if it were an overhead line.

Underground taps off main overhead lines usually present no unusual overcurrent coordination problems. They can be economically fused. If coordination with fuses cannot be achieved, consideration can be given to single-phase or three-phase sectionalizers set for 1 or 2 counts.

CHAPTER V

SAMPLE PROBLEM (SMALL SUBSTATION)

This sample problem is to illustrate the procedure only and the results are not necessarily the best or the only way in which the system may be sectionalized. The sample substation area selected for sectionalizing is shown in Figure 5. A new study for this area is required because of an increase in supply voltage from 33 kV to 69 kV. In purchasing new equipment, it has been decided to increase the capacity of the substation transformers to 3000 kVA. Also, distribution system improvements over the past several years have made it necessary to restudy the entire sectionalizing plan for the substation area.

The following information is necessary in order to complete the sectionalizing study:

1. From Records:

   Schematic diagram of substation area showing tentative or existing sectionalizing points. (See Figure 5)

   Peak load currents at tentative or existing sectionalizing points.

2. From Power Supplier:

   The following data has been obtained from the power supplier for the Trenton substation:

   Maximum three-phase fault current at 69 kV = 2490 amperes

   Maximum fuse permitted = 60 amperes

   Acceptable fuse supplier = manufacturer S

3. From Supply Side Fuse Manufacturer:

   Time-current curves for 69 kV fuse links

4. From the Substation Transformer Manufacturer or From Transformer Nameplate:

   Transformer damage curve - See Figure 27.

   Transformer impedance = 7 percent

   Transformer rating = 1000 kVA (per phase)

   Transformer ratio = 69 kV to 12.5/7.2 kV

5. From ANSI Standard

   Table of recloser ratings (see Figure 10 and 11)

6. <u>From Manufacturers whose Reclosers, Sectionalizers, and Distribution Fuse Links have been Selected for Use:</u>

Time-current curves for various ANSI standard line number reclosers.

Table of ratings for automatic line sectionalizers.

Time-current curves for NEMA Type K or T rated fuse links.

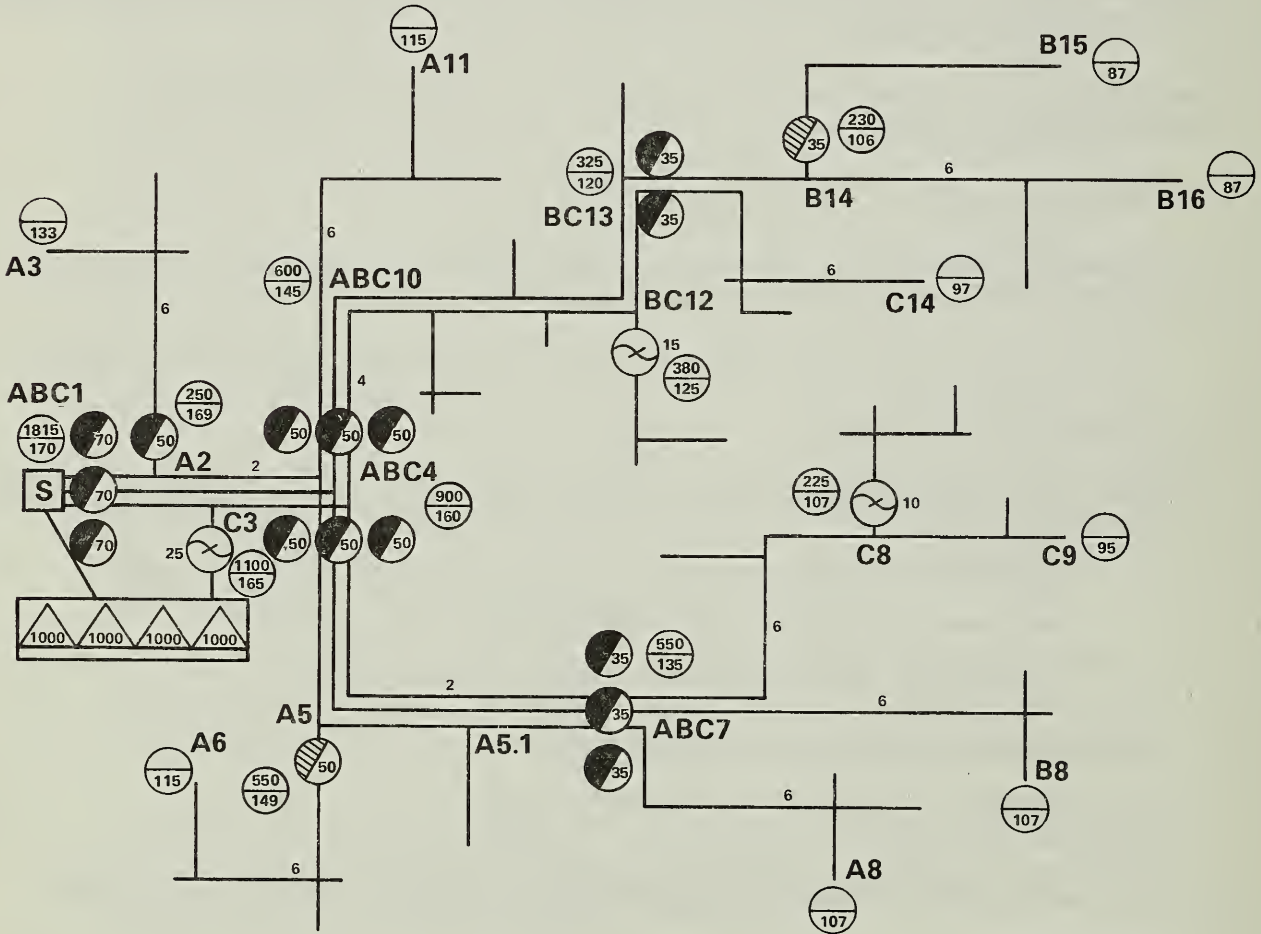


Figure 5. Circuit Diagram of Trenton substation area for sample problem
Note - This drawing is for illustrative purposes only. For requirements of Circuit Diagram, see REA Bulletins 40-4 and 60-1.

<u>Solution</u>

A. <u>Computation of Source Impedance on The Load Side of the Substation</u>

The source impedance information in this example is given by the supplier as the maximum three-phase fault current, I_{3S}=2490 amperes, on the 69 kV

side of the substation transformer.

To determine the line-to-ground source impedance in ohms on the 12.5/7.2 kV base, refer to Table I, 1-b; for the line-to-line source impedance, refer to Table III, 1-b; for the three-phase source impedance refer to Table II, 1-b.

Example: Calculation of the line-to-ground source impedance.

$$Zs = \frac{2}{\sqrt{3}} \quad \frac{E_L^{\ 2}}{I_{3S}\ Es_{\ (L-L)}} \text{ ohms} \qquad \text{Table II, 1-b}$$

Using the given information the line-to-ground source impedance is calculated as follows:

$$Zs = \frac{2}{\sqrt{3}} \times \frac{(7200\ V)^2}{(2490)\ (69000V)} = .348 \text{ ohms}$$

The source impedance in this example is assumed to be all reactive. Therefore, the phase angle is 90 degrees.

$$Zs = 0 + j\ .348$$

The same procedure is followed for calculating the three-phase and line-to-line source impedances. The results are recorded on the sample form shown in Figure 8a.

B. <u>Calculation of Substation Transformer Impedance</u>

The following information is supplied by the manufacturer or is obtained from the nameplate of the transformer:

Transformer damage curve - See Figure 27

Transformer impedance = 7 percent

Transformer rating 1000 kVA per phase, OA rating

Transformer ratio = 69 kV - 12.5/7.2 kV

To determine the line-to-ground transformer impedance, on the 12.5/7.2 kV base, refer to Table I, 2; for the line-to-line transformer impedance, refer to Table III, 2; and for the three-phase transformer impedance, refer to Table II, 2.

Example: <u>Calculation of Line-to-Ground Transformer Impedance</u>.

$$Zt \text{ (ohms)} = \frac{Zt \text{ (percent) } E_L^{\ 2}}{\text{(kVA per phase) (100,000)}}$$

Using the above data:

$$Zt \text{ (ohms)} = \frac{(7)}{(1000)} \frac{(7200\ V)^2}{(100{,}000)} = 3.629$$

The ratio of the transformer reactance to resistance may be obtained from the manufacturer; if unavailable, the following relationship will be adequate in determining the ratio.

$Rt = .2\ Zt$ $\quad$ $Xt = .98\ Zt$ Table I, II, III - 2

The line-to-ground transformer impedance becomes:

$Zt = R_t + jX_t$

$Zt = .726 + j\ 3.556$

The same procedure is followed for calculating the line-to-line and three-phase substation transformer impedances.

C. Computation of Fault Current at Load Side of the Substation

The fault current at the substation for each of the three types of faults is obtained from $I = E_L / Z$ total

Where E_L = the line-to-neutral voltage of the system

Z total = the vector sum of the impedance from the location of the fault back to the source.

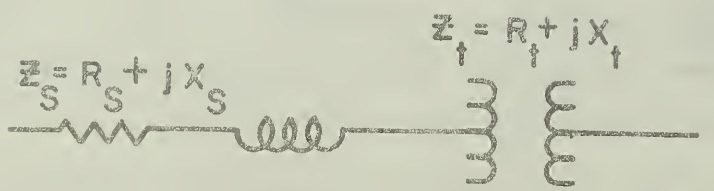


Figure 6

Example: Calculate the maximum line-to-ground fault current on the load side of the substation.

E = 7200 V
Z = Z total

Zs = 0 + j .348
Zt = .726 + j 3.556
Z total = .726 + j 3.904
Z total = 3.971 ohms

$$I = E_L \; Z_{total} = \frac{7200}{3.971} = 1813 \text{ amperes}$$

The minimum fault current at the load side of the substation transformer is obtained by adding 40 ohms fault resistance to the resistance of the source and substation transformer for the line-to-ground fault condition with minimum generation.

Example: Determine minimum fault current at load side of substation.

$$\begin{aligned} Zs &= 0 + j\ .348 \\ Zt &= .726 + j\ 3.556 \\ \hline Z_{total} &= .726 + j\ 3.904 \\ &\ +40 \ + j\ 0 \\ \hline Z_{total\ min.} &= 40.726 + j\ 3.904 = 40.91 \text{ ohms} \\ I_{line\text{-}to\text{-}ground\ min.} &= \frac{7200}{40.91} = 176 \text{ amperes} \end{aligned}$$

The minimum fault current at the load side of the substation equals 176 amperes. These values should be entered on the current data sheet and on the circuit diagram at the substation location.

Computation of Fault Currents on the Line

The REA graphical method for determining fault currents which is described in Appendix A is used in this sample problem although other methods are also acceptable. A slide rule fault current calculator may be used if the source is large and if the slide rule is specially designed for multi-grounded wye systems. However, such calculators must not be used to determine fault currents at the substation. Also, where the calculated maximum fault current at the substation is greater than 1250 amperes, slide rule fault current calculators should not be used to determine fault currents within eight kilometers of the substation. At high fault current locations, their use may lead to the selection of the wrong size and class of recloser.

The current diagram and current data sheet for line-to-ground fault currents are shown in Figures 7 and 8a, 8b and 8c respectively. Note that the points were not plotted nor recorded for the maximum fault current at the end of the taps since it is necessary to know only the minimum currents at these points.

The three-phase and line-to-line current diagrams are not shown because the procedure for calculating these currents is the same as for the line-to-ground short-circuit currents. In making a sectionalizing study of an actual system which has three-phase and V-phase lines, three-phase fault current calculations should be made for all sectionalizing points on the three-phase lines using the three-phase current diagram, and line-to-line fault current calculations should be made for all sectionalizing points on the three-phase and V-phase lines using the line-to-line

current diagram. The starting points on the three-phase diagram should be the total resistance and total reactance values for maximum and minimum conditions on the load side of the substation for three-phase faults. The starting point on the line-to-line diagram should be the total resistance and total reactance values, for the maximum and minimum conditions, on the load side of the substation for line-to-line faults.

7,200 VOLT SHORT CIRCUIT CURRENT DIAGRAM NO. I LINE-TO-GROUND FAULTS

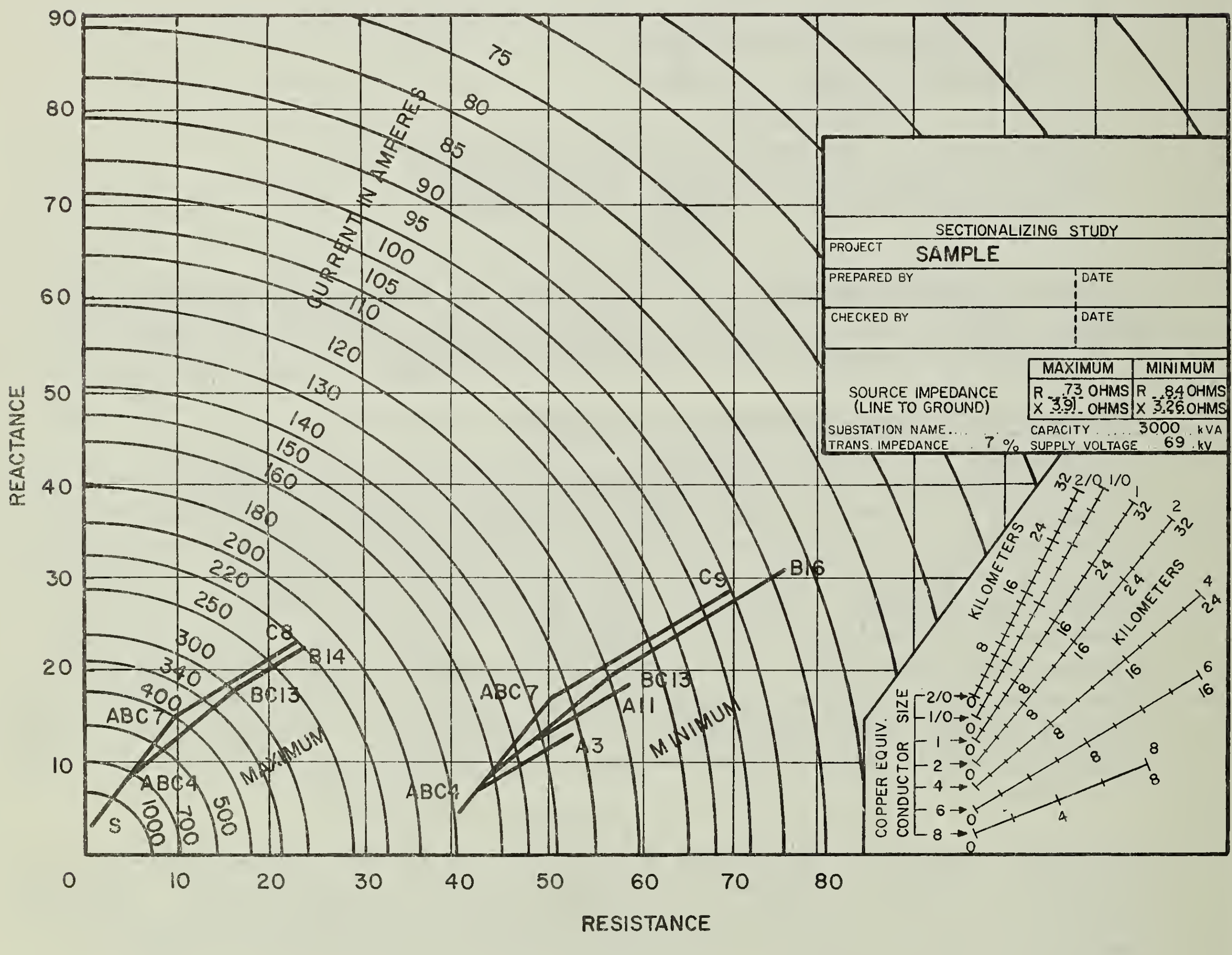


Figure 7. Short circuit current diagram for sample problem.

U. S. DEPARTMENT OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION SECTIONALIZING STUDY SHORT CIRCUIT CURRENT DATA SHEET	DATE	SHEET 1 OF 3 SHEETS
	PROJECT DESIGNATION Sample	SYSTEM LINE-TO-GR VOLTAGE 7200
Instructions-See REA Bulletin 61-2	SUBSTATION NAME	PREPARED BY

1. Point	Sub.	A2	A3	C3	ABC 4	A5	A6	ABC 7
2. Preceding Point on Line Toward Substation		Sub.	A2	A2	C3	ABC 4	A5	A5
3. Kilometers from Previous Point		2.41	7.24	.80	2.41	4.83	8.05	5.63
4. ACSR Conductivity Size for Section		2	6	2	2	2	6	2
5. Three Phase Impedance for Section								
6. Total Three Phase Impedance from Source								
7. Line-Line Impedance for Section								
8. Total Line-Line Impedance from Source								
9. Line-Ground Impedance for Section								
10. Total Line-Ground Impedance from Source								
11. Three Phase Fault Current								
12. Line-Line Fault Current								
13. Line-Ground Fault Current	1813	1250	380	1100	800	550	--	390
14. Minimum Line-Ground Fault Current	176	170	133	165	160	149	115	135

Figure 8a. Short circuit current data sheet for sample problem.

U. S. DEPARTMENT OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION SECTIONALIZING STUDY SHORT CIRCUIT CURRENT DATA SHEET	DATE	SHEET 2 OF 3 SHEETS
	PROJECT DESIGNATION Sample	SYSTEM LINE-TO-GR VOLTAGE 7200
Instructions-See REA Bulletin 61-2	SUBSTATION NAME	PREPARED BY

1. Point	C8	C9	B8	A8	ABC10	A11	BC12	BC13
2. Preceding Point on Line Toward Substation	ABC7	C8	ABC7	ABC7	ABC4	AB10	AB10	BC12
3. Kilometers from Previous Point	8.05	4.83	9.66	8.05	4.02	7.24	6.44	2.41
4. ACSR Conductivity Size for Section	6	6	6	6	4	6	4	4
5. Three Phase Impedance for Section								
6. Total Three Phase Impedance from Source								
7. Line-Line Impedance for Section								
8. Total Line-Line Impedance from Source								
9. Line-Ground Impedance for Section								
10. Total Line-Ground Impedance from Source								
11. Three Phase Fault Current								
12. Line-Line Fault Current								
13. Line-Ground Fault Current	225	----	----	----	525	----	340	290
14. Minimum Line-Ground Fault Current	107	95	102	107	145	115	125	120

Figure 8b. Short circuit current data sheet for sample problem.

U.S. DEPARTMENT OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION SECTIONALIZING STUDY SHORT CIRCUIT CURRENT DATA SHEET Instructions - See REA Bulletin 61-2		DATE PROJECT DESIGNATION Sample SUBSTATION NAME			SHEET 3 OF 3 SHEETS SYSTEM LINE-TO-GR VOLTAGE 7200 PREPARED BY		
1. Point	C14	B14	B16	B15			
2. Preceding Point on Line Toward Substation	BC13	BC13	B14	B14			
3. Kilometers from Previous Point	8.05	4.02	8.05	8.05			
4. ACSR Conductivity Size for Section	6	6	6	6			
5. Three Phase Impedance for Section							
6. Total Three Phase Impedance from Source							
7. Line-Line Impedance for Section							
8. Total Line-Line Impedance from Source							
9. Line-Ground Impedance for Section							
10. Total Line-Ground Impedance from Source							
11. Three Phase Fault Current							
12. Line-Line Fault Current							
13. Line-Ground Fault Current	----	230	----	----			
14. Minimum Line-Ground Fault Current	97	106	87	87			

Figure 8c. Short circuit current data sheet for sample problem.

After all fault currents have been determined, enter the maximum and minimum fault currents at each sectionalizing point and the minimum fault current at the end of each circuit or tap directly on the circuit diagram.

Selection of Sectionalizing Devices at Substation

The first step is to plot the time-current transformer damage curve on the coordination chart shown in Figure 9. Next select the substation recloser size. A study of the recloser ratings of Mfg. "X" shows that a recloser of 50 amperes or larger size is needed to interrupt the maximum fault current of 1813 amperes.

The full load current of the transformer bank is 138 amperes. Therefore, for complete protection of the transformers against minimum faults and sustained overloads, a recloser size of 70 amperes or smaller is necessary. This limits the choice between a 50 or 70 ampere recloser of line 2, Figures 10 and 11. The maximum load current of the most heavily loaded feeder is 35 amperes and at the

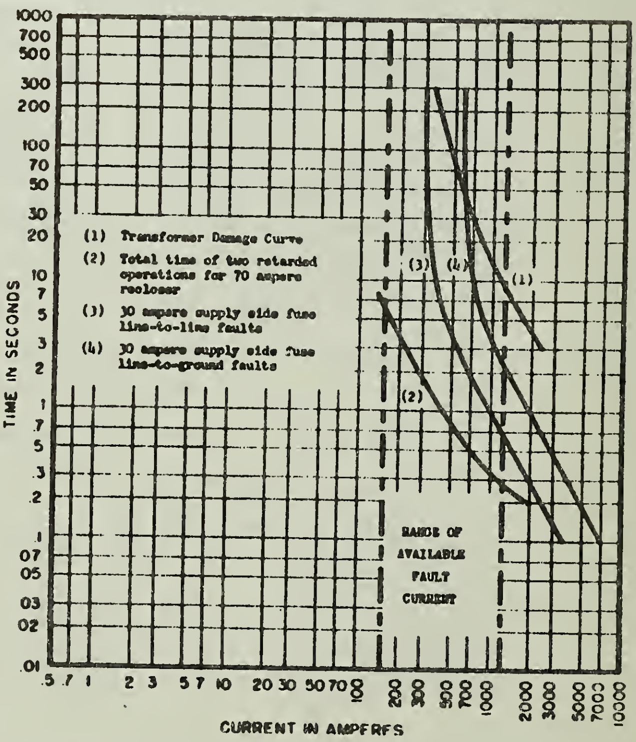


Figure 9. Substation coordination chart for sample problem.

time the substation will be overloaded the maximum current will be 65 amperes. On this basis the 70 ampere recloser is selected although it is recognized that inrush currents may prove troublesome at the time

Rated Maximum Voltage, Rated Continuous Current, Rated Interrupting Current, Rated Impulse Withstand Voltage, and Performance Characteristics of Reclosers

				Low-Frequency Insulation Level Withstand Test,* kV rms		Current Ratings, Amperes		Standard Operating Duty						
								Percent of Interrupting Rating						
								15-20		45-55		90-100		
Line No.	Nominal System Voltage, kV rms	Rated Maximum Voltage kV rms	Rated Impulse Withstand Voltage kV Crest	1-minute Dry	10-second Wet	Maximum Continuous, 60 Hz	Symmetrical Interrupting+ at Rated Maximum Volts	Minimum X/R	Number of Unit Operations	Minimum X/R	Number of Unit Operations	Minimum X/R	Number of Unit Operations	Total Number of Unit Operations
(Col 1)	(Col 2)	(Col 3)	(Col 4)	(Col 5)	(Col 6)	(Col 7)	(Col 8)	(Col 9)	(Col 10)	(Col 11)	(Col 12)	(Col 13)	(Col 14)	(Col 15)
1	14.4	15.0	95	35	30	50	1 250	2	40	4	40	8	20	100
2	14.4	15.5	110	50	45	100	2 000	2	32	5	24	10	12	68
3	14.4	15.5	110	50	45	280	4 000	3	32	6	20	12	12	64
4	14.4	15.5	110	50	45	400	4 000	3	32	6	20	12	12	64
5	14.4	15.5	110	50	45	500	8 000	3	28	7	20	14	10	58
6	14.4	15.5	110	50	45	560	16 000	4	16	8	8	16	4	28
7	14.4	15.5	110	50	45	560	16 000	4	24	8	20	16	8	52
8	14.4	15.5	110	50	45	120	16 000	4	21	8	20	16	8	52
9	24.9	27.0	150	60	50	100	2 500	2	32	8	24	12	12	68
10	24.9	27.0	150	60	50	400	6 000	4	28	8	24	15	10	62
11	24.9	27.0	150	60	50	560	8 000	4	28	8	20	15	10	58
12	24.9	27.0	150	60	50	1 120	8 000	4	28	8	20	15	10	58
13	34.5	38.0	200	80	70	560	12 000	4	28	8	20	15	10	58
14	46.0	48.3	250	105	95	560	10 000	4	28	8	20	15	10	58
15	69.0	72.5	350	160	140	560	8 000	4	28	8	20	16	10	58

*These are performance characteristics specified as test requirements in these standards.

+See Table 3 for complete data on rated interrupting currents for reclosers using smaller series coil sizes or reduced minimum trip settings.

Figure 10

Continuous Current and Interrupting Current Ratings

	Interrupting Current Rating in Amperes at Rated Maximum Voltage													
	Recloser Line No.													
	1	2	3	4	5	6-7	8	9	10	11	12	13	14	15
Continuous Current Rating, Amperes	Series Coil Reclosers													
5	125	--	--	--	--	--	--	--	--	--	--	--	--	--
10	250	--	--	--	--	--	--	400	--	--	--	--	--	--
15	375	--	--	--	--	--	--	600	--	--	--	--	--	--
25	625	1 000	1 500	1 500	--	--	--	1 000	1 500	--	--	--	--	--
35	875	1 400	2 100	2 100	--	--	--	1 400	2 100	--	--	--	--	--
50	1 250	2 000	3 000	3 000	--	--	--	2 000	3 000	--	--	--	--	--
70	--	2 000	4 000	4 000	--	--	--	2 500	4 200	--	--	--	--	--
100	--	2 000	4 000	4 000	6 000	--	--	2 500	6 000	--	--	--	--	--
140	--	--	4 000	4 000	8 000	--	--	--	6 000	--	--	--	--	--
200	--	--	4 000	4 000	8 000	--	--	--	6 000	--	--	--	--	--
280	--	--	4 000	4 000	8 000	--	--	--	6 000	--	--	--	--	--
400	--	--	--	4 000	8 000	--	--	--	6 000	--	--	--	--	--
560	--	--	--	--	8 000	--	--	--	--	--	--	--	--	--
800	--	--	--	--	--	--	--	--	--	--	--	--	--	--
1 120	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Minimum Trip Setting	Non-Series Coil Reclosers													
100	--	--	--	3 000	--	--	--	--	3 000	--	--			
140	--	--	--	4 000	--	--	--	--	4 200	--	--			
200	--	--	--	4 000	6 000	6 000	--	--	6 000	6 000	6 000	6 000	6 000	6 000
280	--	--	--	4 000	8 000	8 400	--	--	6 000	8 000	8 000	8 400	8 400	8 000
400	--	--	--	4 000	8 000	12 000	12 000	--	6 000	8 000	8 000	12 000	10 000	8 000
560	--	--	--	4 000	8 000	16 000	16 000	--	6 000	8 000	8 000	12 000	10 000	8 000
800	--	--	--	4 000	8 000	16 000	16 000	--	6 000	8 000	8 000	12 000	10 000	8 000
1 120	--	--	--	--	8 000	16 000	16 000	--	--	8 000	8 000	12 000	10 000	8 000
1 600	--	--	--	--	--	--	16 000	--	--	--	8 000	--	--	--
2 240	--	--	--	--	--	--	16 000	--	--	--	8 000	--	--	--

NOTE: For interrupting current ratings at other than rated voltage, consult the manufacturer. The interrupting current ratings of reclosers are not generally on a constant kVA basis.

Figure 11

of maximum substation development. A recloser setting of two fast and two slow operations has proven satisfactory on this system and consequently this setting will be used. Plot the total time of the two slow operations on the coordination chart, Figure 9, since current will flow through the supply side fuse for this time on a sustained fault. The fast operating times and the fuse cooling times between operations may be neglected.

Next, select a supply side fuse within the limitation set by the power supplier. The fuse should permit the transformer bank to carry a reasonable overload and should also withstand, without damage, transformer energizing inrush current. If a fuse will not melt in one-tenth of a second at twelve times transformer full load current it will be satisfactory for inrush current. Fusing for 140% transformer full load current is an acceptable practice although other fusing practices may be used. Considering inrush current and permissible overload a 30E fuse is selected for this application.

Next plot the 30 E minimum melting fuse characteristic curve on the distribution voltage base on the coordination chart for the line-to-line fault condition. This is done by multiplying the current values of the 30 E fuse characteristic by the ratio:

$$\frac{E_{s(L-L)}}{2E_L} \quad \text{or} \quad \frac{69000V}{2 \times 7200\ V}$$

Now plot the 30 E fuse time-current characteristic curve on the distribution voltage base on the coordination chart for line-to-ground fault conditions. This is done by multiplying the 30 E minimum melting time-current characteristic by the ratio:

$$\frac{E_{s(L-L)}}{E_L} \quad \text{or} \quad \frac{69000V}{7200\ V}$$

The substation coordination chart is now complete. Note that the 30 E fuse does not protect the substation transformers against line-to-ground fault currents below 600 amperes. Complete protection against all faults could be obtained by using a fuse which would melt at 15 amperes but this would permit loading of the substation to only a little more than 50 percent of its capacity. It becomes necessary, therefore, to accept the possibility of transformer damage or loss of life in the event of a line-to-ground fault inside this substation smaller than 600 amperes. This is probably not as great a risk as may appear since it is likely that the time damage curve of the transformer is conservative. Also, a fault inside the substation with 10 ohms or more fault resistance is required to cause damage.

Selection of Line Recloser and Sectionalizers

Proceed to the selection of recloser and line sectionalizer sizes at all sectionalizing points where the decision has been made to use

these devices. Select reclosers of descending size for the main circuit and drop two sizes for branch circuits wherever possible. Select the sectionalizers in accordance with the manufacturer's ratings. In general, sectionalizers are coordinated by selecting the minimum counting current to be equal to (or slightly less than) the minimum tripping current of the back-up recloser, and the number of counts set to be one fewer than the recloser trips to lockout.

Check load currents and maximum fault current at the recloser installation and minimum fault current at the end of the section protected by the recloser and compare with recloser ratings given in Figures 10 and 11. The recloser and sectionalizer sizes for the sample problem are shown in the circuit diagram of Figure 5.

Selection of Branch Circuit Fuses

Plot the recloser time-delay curve and the fast time-current characteristic curve of each recloser size protecting a branch line fuse on a coordination chart using a separate chart for each recloser size. The recloser fast curve should be adjusted by a factor of 1.5 if two fast curves are used. Next plot the minimum melting and the maximum clearing time-current characteristic of the fuse or fuses which lie between the fast and slow recloser curves for the range of fault currents available in the zone protected by the recloser-fuse combination. A coordination chart for the fuse at C3 is shown in Figure 12 and all fuse sizes are shown on the circuit diagram of Figure 5.

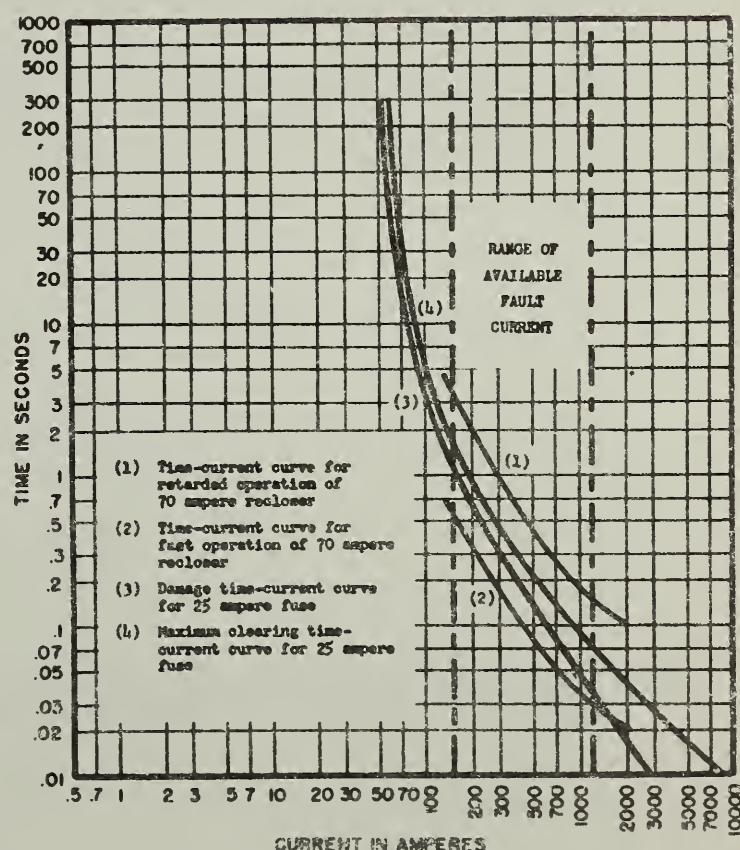


Figure 12. Coordination chart for recloser-fuse combination of sample problem.

Tabulation of Sectionalizing Devices

The sectionalizing devices are now tabulated and their ratings checked against load and fault currents as recorded in Figure 13.

SECTIONALIZING DEVICE SCHEDULE
SHEET 1 OF 1

System Designation: Sample		Substation or Metering Point Designation:	
Date:	Prepared by:	Installed Capacity:	Source-Load Voltage:

Instructions - See REA Bulletin 62-1	Circuit Breakers or Reclosers	Fuses or Sectionalizers
Substation - Supply Side		Mfg. "A" 69 kV
Substation - Load Side	Mfg. "X" ACR	
Distribution Lines		Mfg. "X" Type "T"

Point	Load Current	Fault Current (1)		Existing Device				Proposed Device				Reason For Change (3)
		Max.	Min.	No.	Type (2)	Rating	G-Trip	No.	Type (2)	Rating	G-Trip	
ABC1	35	1815	160					3	ACR	70a		
A2	2	1250	133					1	ACR	50a		
C3	1	1100	160					1	Fuse	25a		
ABC4N	17	900	115					3	ACR	50a		
ABC4S	15	900	115					3	ACR	50a		
A5	2	550	115					1	Sect	50a		
ABC7	10	550	95					3	ACR	35a		
C8	1	225	95					1	Fuse	10a		
BC12	1	380	115					2	Fuse	15a		
BC13	8	325	87					2	ACR	35a		
B14	3	230	87					1	Sect	35a		

NOTES:
(1) Maximum at point - Minumum at end of controlled section with 40 ohms fault resistance
(2) ACR - Automatic Circuit Recloser , SECT - Sectionalizer
(3) IC - Interrupting Capacity , LC - Load Current , C - Coordination , NC - No Change, A - Additional Device

Figure 13. Tabulation of sectionalizing devices of sample problem.

CHAPTER VI

SAMPLE PROBLEM (LARGE SUBSTATION)

This sample problem illustrates the typical sectionalizing procedures used when the substation transformer is larger than 5,000 kVA and the available fault current is high. The results in this example are not necessarily the best or the only way the system may be sectionalized. The system selected for sectionalizing is shown in Figure 14. It is assumed that the entire substation is under construction, and a complete sectionalizing study is needed. To get the most long-term benefit out of this sectionalizing study, the load currents are estimated for each feeder when the substation transformer is fully loaded. These estimated future full-load currents are shown in Figure 14. For simplicity, only one of the substation circuits will be sectionalized, Circuit 1.

Basic Data

Source information from power supplier at Bartlett substation -

Maximum three-phase fault current at 115 kV side of substation = 7,168 amperes. Acceptable primary fuse size supplied by any manufacturer, no larger than 100E.

From substation manufacturer -

Transformer time - current damage curve - If unavailable, consult ANSI Std. C57-92, Section 06.200

Transformer Impedance = 7 percent
Transformer OA Rating = 10,000 kVA
Transformer Ratio = 115 kV-12.5/ 7.2 kV

From manufacturer whose reclosers and fuses have been selected for use -

Time-current curves for 115 kV power fuses.
Ratings of distribution and power class reclosers.
Time-current curves of the selected reclosers.
Ratings of distribution line fuses.
Time-current curves of distribution line fuses.

From records -

Circuit diagram of substation and circuits showing proposed sectionalizing points, conductor sizes, line section distances and full-load currents.

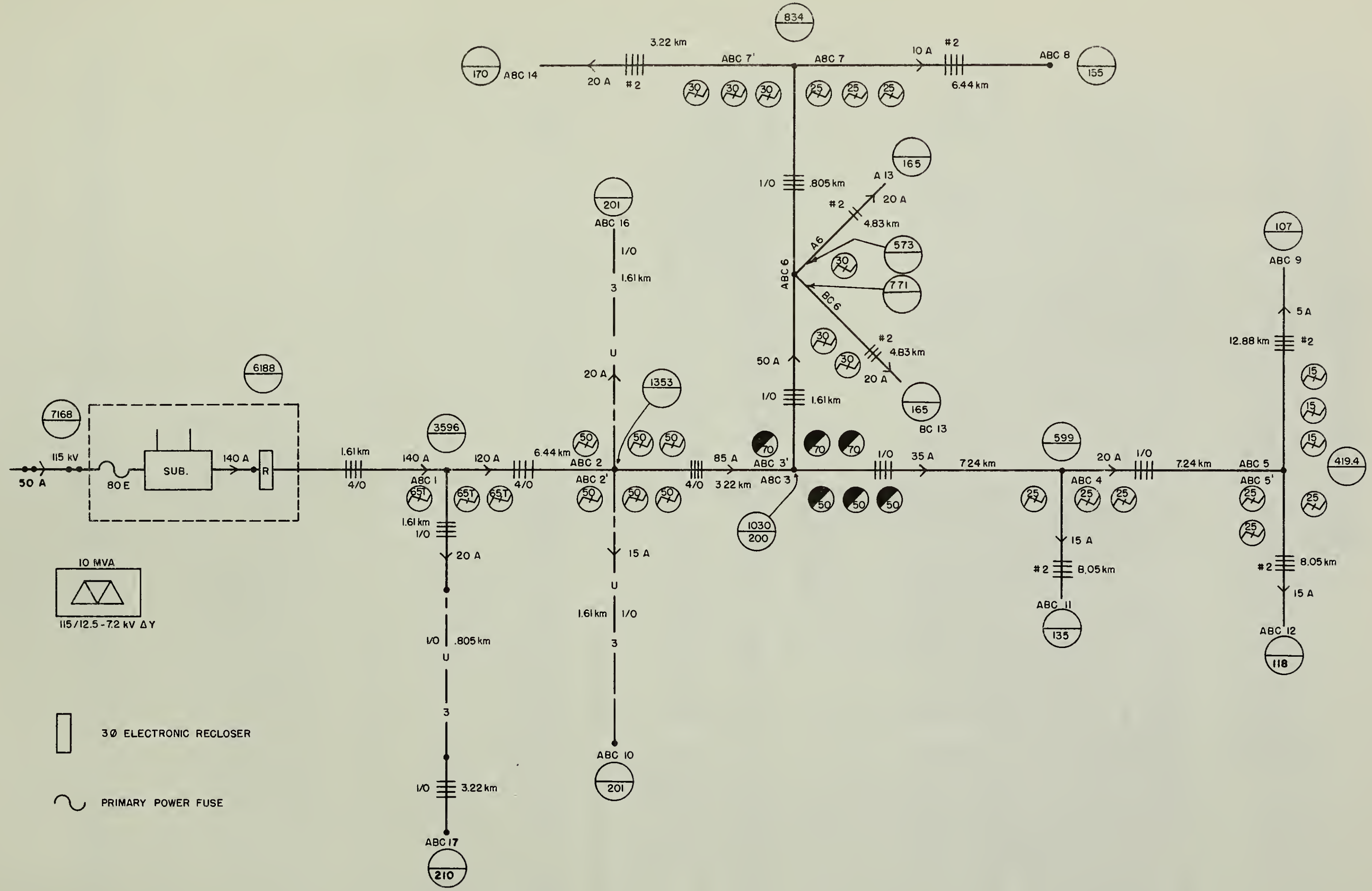


Figure 14. Circuit diagram of Bartlett substation area for sample problem. Note - This drawing is for illustrative purposes only. For requirements of circuit diagram, see REA Bulletins 40-4 and 60-1.

Solution

A. Calculation of Fault Currents

Maximum fault currents are calculated at each proposed sectionalizing location. Minimum fault currents are calculated for each device at the end of the line section the device is designed to protect.

The first step in the computation of fault currents is to determine the source impedance, substation transformer impedance, and distribution line impedance, in ohms, referred to the distribution voltage level as a common base.

1. Source Impedance

The source impedance information in this example is given by the power supplier as maximum three-phase fault current, I_{3s} = 7168 amperes, on the 115 kV side of the substation transformer.

To determine the three-phase source impedance referenced to the 12.5/7.2 kV bus, refer to Table II, 1-b; for the line-to-line source impedance, refer to Table III, 1-b; and for the line-to-ground source impedance, refer to Table I, 1-b.

Example: Calculation of three-phase source impedance

$$Zs = \sqrt{3} \frac{E_L^2}{I_{3s} \; Es \; (1-1)} \quad \text{ohms} \qquad \text{Table II, 1-b}$$

Using the given information, the three-phase source impedance is calculated as follows:

$$Zs = \sqrt{3} \frac{(7.2 \text{ kV})^2}{(7168) \; (115 \text{ kV})} = .109 \text{ ohms}$$

If the associated phase angle is not given with the source information, an assumption must be made as to what part of the source impedance is resistance and reactance. Since no fault current phase angle is given, it is assumed the source impedance is all reactance.

$$Zs = 0 + j\ .109 \text{ ohms}$$

The same procedure is followed for calculating the line-to-line and line-to-ground source impedances. The results are recorded on the sample form shown in Figure 15a.

The next impedance to be calculated is the substation impedance.

2. Substation Impedance

The following information is supplied by the manufacturer or is obtained from the transformer's nameplate.

Three-phase, 10 MVA OA rated transformer
High side 115 kV

Low side 12.5/7.2 kV
Percent impedance - 7 percent

To determine the transformer impedance (ohmic) to a three-phase fault referred to the 12.5/7.2 kV base, see Table II, 2. To find the impedance of the transformer to a line-to-line fault see Table III, 2. To find the transformer impedance to a line-to-ground fault, see Table I, 2.

Example: <u>Calculation of three-phase Transformer Impedance</u>

$$Zt = \frac{Zt\ (\text{percent})\ \ E_L^2}{(\text{kVA per phase})\ \ (100{,}000)} \qquad \text{Table II-2}$$

Using the transformer data:

$$Zt = \frac{(7) \times (7200\ V)^2}{(3333) \times (100{,}000)} = 1.09 \text{ ohms}$$

The ratio of transformer reactance to resistance may be obtained from the manufacturer; if unavailable, the following relationship will be adequate in determining the ratio.

$$Rt = (.2)\ (Zt) \qquad Xt = (.98)\ (Zt) \qquad \text{Table I, II, III-2}$$

The impedance of the transformer to a three-phase fault becomes:

$$Zt = Rt + jXt$$

$$Zt = .218 + j1.07 \text{ ohms}$$

The same procedure is followed in calculating the substation transformer impedance to a line-to-line and a line-to-ground fault. The results are recorded on the sample form shown in Figure 15a.

3. <u>Distribution Line Impedances</u>

The last impedance to be calculated is the distribution line impedance. To determine the overhead and underground line impedances for three-phase faults, refer to Table II, 3; for line-to-line faults, refer to Table III, 3; and for line-to-ground faults, refer to Table I, 3.

Multiply each of the values obtained from the appropriate table by the number of kilometers of each conductor size from the substation to fault location and record the results in sample form shown in Figures 15 (a, b and c).

Example: <u>Calculation of the Three-Phase Distribution Line Impedance</u>

Assume fault location of ABC 3, refer to Figure 14. The conductor size from the fault location to substation is 4/0 ACSR and is 11.26 km in length.

From Table II, 3 4/0 ACSR

$R_1 = .274 \frac{\text{ohm}}{\text{km}}$ $X_1 = .442 \frac{\text{ohm}}{\text{km}}$

$R_{dist} = (R_1)(11.26)$ $X_{dist} = (11.26)(X1)$

$R_{dist} = 3.09$ ohms $X_{dist} = 4.98$ ohms

The same procedure is used for each assumed fault location for three-phase, line-to-line and line-to-ground faults and the results are recorded on the sample forms of Figures 15 (a, b and c).

Computation of Fault Current

With the three-phase, line-to-line and line-to-ground source, transformer and distribution line impedances determined, the fault current calculation is a simple matter of summing up the respective impedances vectorially from the fault location back to the source and then using the following equation:

$$I\ fault = \frac{E_L}{(Rs + Rt + Rdist + Rf)^2 + (Xs + Xt + Xdist)^2}$$

When calculating maximum fault current, assume Rf = 0.

When calculating minimum fault current, use assumed value for fault resistance, Rf.

Example: Calculate Maximum Three-Phase Fault Current at ABC (3), Figure 14

From the previous examples:

Three-phase source impedance, Zs = 0 + j .109 ohms
Three-phase transformer impedance, Zt = .218 + j 1.07 ohms
Three-phase distribution line impedance, Zdist = 3.09 + j 4.98 ohms

Substituting these values into the fault current formula:

I three-phase maximum = I_{3s} maximum =

$$\frac{E_L}{(.218 + 3.09)^2 + (.109 + 1.07 + 4.98)^2} = 1030 \text{ Amperes}$$

The same procedure is used for calculating the three-phase, line-to-line and line-to-ground fault currents. The results are recorded in the sample form shown in Figures 15 (a, b and c).

The maximum and minimum fault current each sectionalizing device may interrupt is recorded on the form in Figure 15 and on the circuit map in Figure 14. The maximum fault current is located at the location of the device and the minimum fault current is located at the end of

the line section the device is protecting.

In general, on three-phase and single-phase lines, only the three-phase and single-phase fault currents need be calculated, since a line-to-line fault usually will result in neither a maximum or minimum value. However, on "V"-phase lines, the line-to-line fault will yield the maximum value at some distance away from the substation and should be calculated.

U. S. DEPARTMENT OF AGRICULTURE			DATE			SHEET 1 OF 3 SHEETS		
RURAL ELECTRIFICATION ADMINISTRATION			PROJECT DESIGNATION Any State 19, Alpha			SYSTEM LINE-TO-GR VOLTAGE 115-12.5/7.2 kV		
SECTIONALIZING STUDY SHORT CIRCUIT CURRENT DATA SHEET			SUBSTATION NAME Bartlett Sub			PREPARED BY ------		
Instructions - See REA Bulletin 61-2								
1. Point	High side of sub	Load side of sub	ABC 1	ABC 2	ABC 3	ABC 4	ABC 5	ABC 9
2. Preceding Point on Line Toward Substation	-----		Load Sub	ABC 1	ABC 2	ABC 3	ABC 4	ABC 5
3. Kilometers from Previous Point	-----		1.61	6.44	3.22	7.24	7.24	12.87
4. ACSR Conductivity Size for Section	-----		4/0	4/0	4/0	1/0	1/0	#2
5. Three Phase Impedance for Section	-----	.218 +j1.07	.441 +j.712	1.76 +j 2.85	.88 +j 1.42	3.98 +j 3.4	3.98 +j 3.4	11.27 +j 6.24
6. Total Three Phase Impedance from Source	+j .109	.218 +j1.18	.66 +j1.89	2.42 +j 4.74	3.3 +j 6.16	7.28 +j 9.56	11.26 +j12.96	22.54 +j19.2
7. Line-Line Impedance for Section	-----	.251 +j1.232	.509 +j.823	2.04 +j 3.29	1.02 +j1.65	4.59 +j 3.92	4.59 +j 3.93	13.04 +j 7.21
8. Total Line-Line Impedance from Source	+j .126	.251 +j1.36	.76 +j2.18	2.8 +j 5.47	3.82 +j7.12	8.41 +j11.05	13.00 +j 14.97	26.04 +j 22.18
9. Line-Ground Impedance for Section	------	.218 +j1.07	.64 +j1.22	2.56 +j 4.88	1.28 +j2.44	5.04 +j 6.52	5.04 +j 6.52	13.11 +j11.75
10. Total Line-Ground Impedance from Source	.073	.218 +j1.143	.86 +j2.36	3.42 +j 7.24	4.7 +j9.68	9.74 +j 16.20	14.78 +j22.72	27.9 +j 34.5
11. Three Phase Fault Current	7168	6000	3596	1353	1030	599	419.4	-----
12. Line-Line Fault Current	------	5206	3119	1172	892	518.5	363	-----
13. Line-Ground Fault Current	------	6188	2867	899	669	381	266	-----
14. Minimum Line-Ground Fault Current	------	238.1	233.6	210.6	200	167.8	143.4	107

Figure 15a. Short circuit current data sheet.

U. S. DEPARTMENT OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION SECTIONALIZING STUDY SHORT CIRCUIT CURRENT DATA SHEET	DATE	SHEET 2 OF 3 SHEETS
	PROJECT DESIGNATION Any State 19, Alpha	SYSTEM LINE-TO-GR VOLTAGE 115-12.5/7.2 kV
Instructions-See REA Bulletin 61-2	SUBSTATION NAME Bartlett Sub	PREPARED BY

1. Point	ABC 6	ABC 7	ABC 8	ABC 17	ABC 10	ABC 16	ABC 11	ABC 12
2. Preceding Point on Line Toword Substotion	ABC 3	ABC 6	ABC 7	ABC 1	ABC 2	ABC 2	ABC 4	ABC 5
3. Kilometers from Previous Point	1.61	.805	6.44	5.63	1.61	1.61	8.05	8.05
4. ACSR Conductivity Size for Section	1/0	1/0	#2	1/0 1/0 URD	1/0 URD	1/0 URD	#2	#2
5. Three Phose Impedonce for Section	.856 +j .757	.44 +j .38	5.64 +j 3.12	----	----	----	----	----
6. Totol Three Phose Impedonce from Source	4.16 +j 6.92	4.60 +j 7.3	10.24 +j10.42	----	----	----	----	----
7. Line-Line Impedonce for Section	1.02 +j 8.73	.51 +j .436	6.52 +j 3.6	----	-----	----	----	----
8. Totol Line-Line Impedonce from Source	4.84 +j 7.99	5.35 +j 8.43	11.87 +j12.93	----	----	----	----	----
9. Line-Ground Impedonce for Section	1.12 +j 1.45	.56 +j .73	6.56 +j 5.88	3.02 +j 3.19	1.56 +j .57	1.56 +j .57	8.2 +j 7.35	8.2 +j 7.35
10. Totol Line-Ground Impedonce from Source	5.82 +j 11.13	6.38 +j11.86	12.94 +j17.74	3.88 +j 5.55	4.98 +j7.81	4.98 +j 7.81	17.94 +j23.55	22.98 +j30.07
11. Three Phose Foult Current	892	834	----	----	----	----	----	----
12. Line-Line Foult Current	771	721.13	----	----	----		----	----
13. Line-Ground Foult Current	573.3	534.6	----	----	----	----	----	----
14. Minimum Line-Ground Foult Current	192.0	187	155	210	201	201	135	118

Figure 15b. Short circuit current data sheet.

U. S. DEPARTMENT OF AGRICULTURE RURAL ELECTRIFICATION ADMINISTRATION SECTIONALIZING STUDY SHORT CIRCUIT CURRENT DATA SHEET	DATE	SHEET 3 OF 3 SHEETS
	PROJECT DESIGNATION Any State 19, Alpha	SYSTEM LINE-TO-GR VOLTAGE 115-12.5/7.2 kV
Instructions-See REA Bulletin 61-2	SUBSTATION NAME Bartlett Sub	PREPARED BY -----

1. Point	BC 13	A 13	ABC 14					
2. Preceding Point on Line Toword Substotion	BC 6	A 6	ABC 7					
3. Kilometers from Previous Point	4.83	4.83	3.22					
4. ACSR Conductivity Size for Section	#2	#2	#2					
5. Three Phose Impedonce for Section	----	----						
6. Totol Three Phose Impedonce from Source	----	----						
7. Line-Line Impedonce for Section	----	----						
8. Totol Line-Line Impedonce from Source	----	----						
9. Line-Ground Impedonce for Section	4.92 +j 4.41	4.92 +j4.41	3.28 +j 2.94					
10. Totol Line-Ground Impedonce from Source	10.74 +j15.54	10.74 +j15.54	9.66 +j 14.8					
11. Three Phose Foult Current	----	----						
12. Line-Line Foult Current	----	----						
13. Line-Ground Foult Current	----	----						
14. Minimum Line-Ground Foult Current	165	165	170					

Figure 15c. Short circuit current data sheet.

B. Selection of Substation Sectionalizing Devices

The first step is to plot the substation transformer time-current damage curve on the coordination chart. (refer to Figure 16). This curve can be obtained from the transformer manufacturer or can be derived using the method in ANSI Std. C57-97, Section 06.200.

The next step is to determine the primary fuse rating. The transformer full-load current at 115 kV, taken from the circuit map, Figure 14, is 50 amperes per phase. Using a 140 percent overload factor, the full-load current equals 70 amperes per phase. The next standard power fuse rating is 80E. The maximum available fault current at the 115 kV bus of the transformer is 7168 amperes. An 80E power fuse with an appropriate fuse holder will satisfy the full load, inrush and interrupting capability requirements. Since the power supplier allows up to a 100E fuse, the 80E is acceptable.

To coordinate the primary fuse with the substation transformer damage curve, the primary fuse time-current curves are referenced to the distribution voltage level for line-to-line and line-to-ground faults. The 80E power fuse minimum melt and total clearing curves are referenced to the 12.5/7.2 kV level by the following factors:

$\frac{E_{s\,(l-l)}}{2\,E_L}$ for line-to-line faults and $\frac{E_{s\,(l-l)}}{E_L}$ for line-to-ground faults. These curves are plotted in Figure 16.

The next step is to determine the substation recloser rating. From the circuit diagram, the maximum available fault current at the recloser location is 6188 amperes. The peak-load current on the circuit being studied is 140 amperes per phase as shown in Figure 14. The calculated minimum fault current to which the substation recloser will have to respond is 200 amperes, at ABC3. A single-phase hydraulic recloser was initially considered; however, the recloser coil rating would have had to be at least 140 amperes, resulting in a minimum trip of 280 amperes. This would exceed the recommended maximum minimum trip setting of 200 amperes and be larger than the calculated minimum fault current which the recloser must sense. A three-phase recloser either hydraulic or electronic, with ground tripping, would be the proper selection in this situation.

An Electronic Type YE recloser was chosen at the substation. Since the peak-load current is 140 amperes, it would appear that a phase-trip setting of 200 amperes would be adequate. While it is adequate as far as load current is concerned the interrupting rating of the electronic recloser with a 200 ampere phase-trip setting is 6000 amperes and the maximum available fault current at the recloser location is 6188 amperes.

phase-trip setting of 280 amperes was selected which provides a recloser interrupting rating of 8400 amperes. The ground trip was set at 200 amperes since the calculated minimum fault current the recloser must sense is 200 amperes. When selecting ground trip settings, care must be taken to insure that the load current of the largest single-phase line device (recloser, sectionalizer, or fuse) is not greater than the minimum ground trip setting.

A sequence of two fast and two delayed operations was selected for the substation recloser. The A and C recloser curves were selected for the fast and delayed operations. Since the recloser is coordinating with load side fuses, the fast curve A is shifted up by a factor of 1.5; and since the recloser is coordinating with the source side fuses, the adjusted, delayed coordinating curve is the sum of the four operating curves, 2A and 2C. The adjusted curves are plotted in Figure 16. The same procedures are used with the ground tripping curves. The fast curve is shifted up by a factor of 1.5 and the adjusted delayed curve is the sum of the four ground trip curves that are plotted in Figure 16.

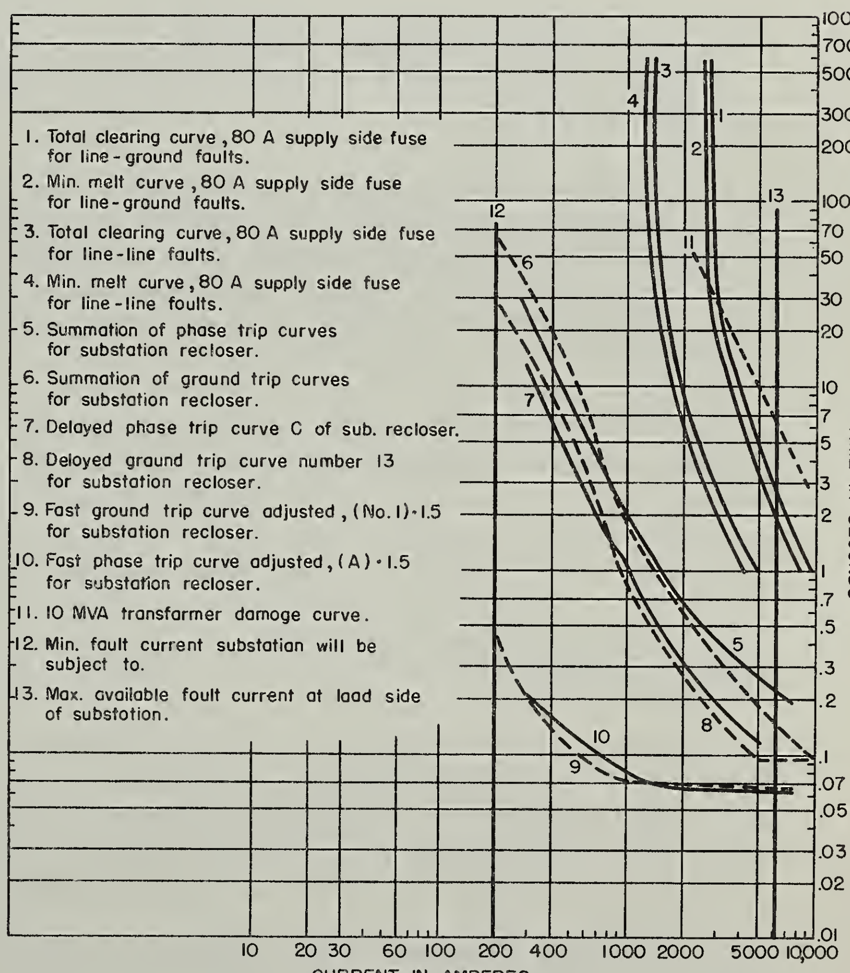


Figure 16. Coordination chart of substation sectionalizing devices for sample problem.

Examining Figure 16, the substation recloser and supply side fuse time-current curves appear properly coordinated. For any available fault current on the distribution system, the substation recloser will lock out before the supply side fuses begin to melt. The supply side fuses are coordinated with the transformer damage curve for line-to-line faults. However, for high impedance line-to-ground faults inside the substation, the supply side fuses will not provide complete protection for the transformer. It becomes necessary, therefore, to accept the possibility of transformer damage (loss of life) in the event of a line-to-ground fault inside the substation smaller than 3200 amperes. Since this is a very remote possibility it is an acceptable risk. The primary fuse rating could be reduced to achieve better coordination with the transformer damage curve but this would limit the loading on the transformer and also possibly result in unnecessary fuse blowing due to inrush currents.

C. Selection of Line Reclosers

In this example, it is proposed that three single-phase reclosers be located at ABC3 and ABC3'. (Refer to Figure 14).

The line reclosers must be designed to carry full-load current, respond to the calculated minimum fault current at the end of the line section it protects and be able to interrupt the maximum fault current at the recloser location.

At ABC3, the load current is 35 amperes per phase, the maximum available fault current is 1030 amperes, and the calculated minimum fault current at ABC9 is 107 amperes. Using this information, three single-phase Type Z reclosers were chosen with coil ratings of 50 amperes, minimum trip rating of 100 amperes, and an interrupting capacity of 3000 amperes.

At ABC3', the load current is 50 amperes per phase, the maximum fault current is 1030 amperes, and the calculated minimum fault current is 155 amperes. From this information, three single-phase, Type Z, reclosers were selected with coil ratings of 70 amperes, minimum trip rating of 140 amperes, and an interrupting capacity of 4200 amperes.

D. Coordination Between Substation Recloser and Distribution Line Fuses and Reclosers

The coordination between the substation recloser, transformer damage curve, and high-side fuses was considered in Section B. This section will deal with the coordination between the substation recloser and the distribution line protective devices up to and including the line reclosers at ABC3, and ABC3' (refer to Figure 14).

The substation recloser must coordinate with line fuses at ABC1, ABC2, ABC2', and line reclosers at ABC3 and ABC3'. The substation recloser uses a sequence of two fast and two slow operations, using the A and C

curve, respectively. The coordination of line reclosers of the same type is a relatively simple matter, since their time-current curves are parallel for different recloser coil ratings. A 50 ampere recloser will coordinate properly with a 25 ampere recloser using the same fast and delayed curves. In this example, the line recloser fast and delayed curves will be A and D,respectively. The substation and line reclosers time-current curves are plotted in Figure 17. As shown in Figure 17, coordination has been achieved between the substation recloser and the line reclosers for permanent faults. However, it should be pointed out that coordination of fast trip curves is not assured. The substation recloser may trip on its fast curve for faults beyond the line reclosers thus resulting in limited cascading. (The substation recloser fast-trip control response curve - which is not plotted - determines the coordination current limit). This is one of the compromises which may have to be made in order to achieve proper coordination between the substation recloser and line fuses. There are techniques which can be employed to prevent or minimize the substation recloser from "over-tripping" the line reclosers. Certain "zone limiting" solid state logic circuits can be employed but with a trade-off of using slower curves for the substation recloser fast trips.

In addition to the line recloser, the substation recloser must coordinate with the sectionalizing fuses up to and including ABC2 and 2'. (Refer to Figure 14). Therefore, the substation recloser fast curve is shifted up by a factor of 1.5 to take into account the fuse heating during the first recloser operation. At ABC2, the load current, maximum fault current and minimum fault current is 20 amperes per phase, 1353 amperes, and 201 amperes, respectively. From this information three 50T fuse links were selected. The minimum melting and total clearing curves are plotted in Figure 17. The 50T fuse will coordinate completely with the substation recloser for the available fault currents. However, if 30T fuses were selected, the fuse would blow before the recloser could respond on fault currents above 1150 amperes at ABC2, resulting in improper coordination. The coordination will be the same at ABC2', since the same size fuse is used.

At ABC1, the load current, maximum and minimum fault current are 20 amperes per phase, 3596 amperes, and 210 amperes, respectively. At this location, 65T fuses were selected and the time-current curves are plotted in Figure 16. Examining Figure 17, it can be seen that the 65T fuse will lose coordination with the substation recloser and start to melt before the recloser can respond when the fault current beyond the fuse is in excess of 2000 amperes. However, if a larger fuse is selected, such as an 80T, it will increase the maximum current coordination at the expense of the lower current coordination. If an 80T fuse was selected, faults under 500 amperes would lock out the substation recloser before the 80T fuses could clear the fault. It is for this reason the 65T fuse is used. As an engineering judgment, it was decided to allow the fuse to clear simultaneous with the first recloser trip (since there will be no temporary faults on the underground cable) for fault currents above 2000 amperes, rather than have the recloser lock out the entire

circuit for a fault current lower than 500 amperes. An automatic line sectionalizer could have been chosen to protect the underground line sections. This would have been an acceptable selection if additional line sectionalizing fuses had been used on the underground cable. Since the 65T fuses at the terminal pole provide adequate protection to the cable, no additional underground sectionalizing fuses are used, and in the interest of economy, the sectionalizer was not chosen for use.

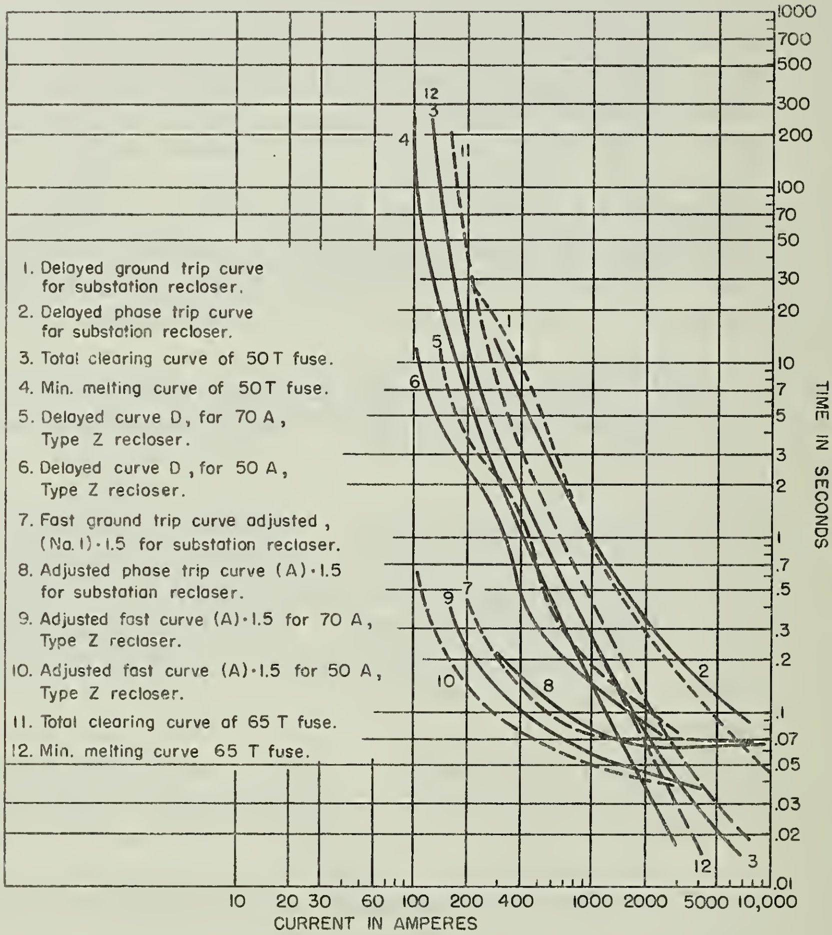


Figure 17. Coordination chart of substation recloser and distribution link fuses and recloser for sample problem.

E. Distribution Line Recloser and Fuse Coordination

The line reclosers have been selected and coordinated with the substation in Section C and D of this sample problem. The next step is to coordinate the line fuses with the line reclosers. (refer to Figure 14)

Three single-phase 50 ampere Type Z reclosers are located at ABC3 with a sequence of two fast and two delayed operations, using the A and D curves. Since the reclosers have two fast operations and are being coordinated with the load-side fuses, the fast curve A is shifted by a factor of 1.5, to take into account the fuse heating during the fast curve operation. Both the D and adjusted A curves are plotted in Figure 18.

The sectionalizing fuses are located at ABC4, ABC5, and ABC5'. The load current, maximum and minimum fault current at ABC4, are 15 amperes, 599 amperes, and 135 amperes, respectively. From this information, three 25T fuses were selected at ABC4. The 25T fuse time-current curves, minimum melting and total clearing, are plotted in Figure 18. Examining Figure 18, the recloser fast operations will respond and interrupt the fault before the fuse starts to melt and the fuse will clear the fault before the recloser locks out for the range of available fault currents.

At ABC5, the load, maximum and minimum fault current, are 5 amperes, 419.4 amperes, and 107 amperes, respectively. Three 15T fuses were selected for this location. The fuse minimum melting and maximum clearing time-current curves are plotted in Figure 18. Examining Figure 18, it can be seen that the 15T fuses will properly coordinate with the 50 ampere, Type Z recloser for the available fault current beyond the fuse.

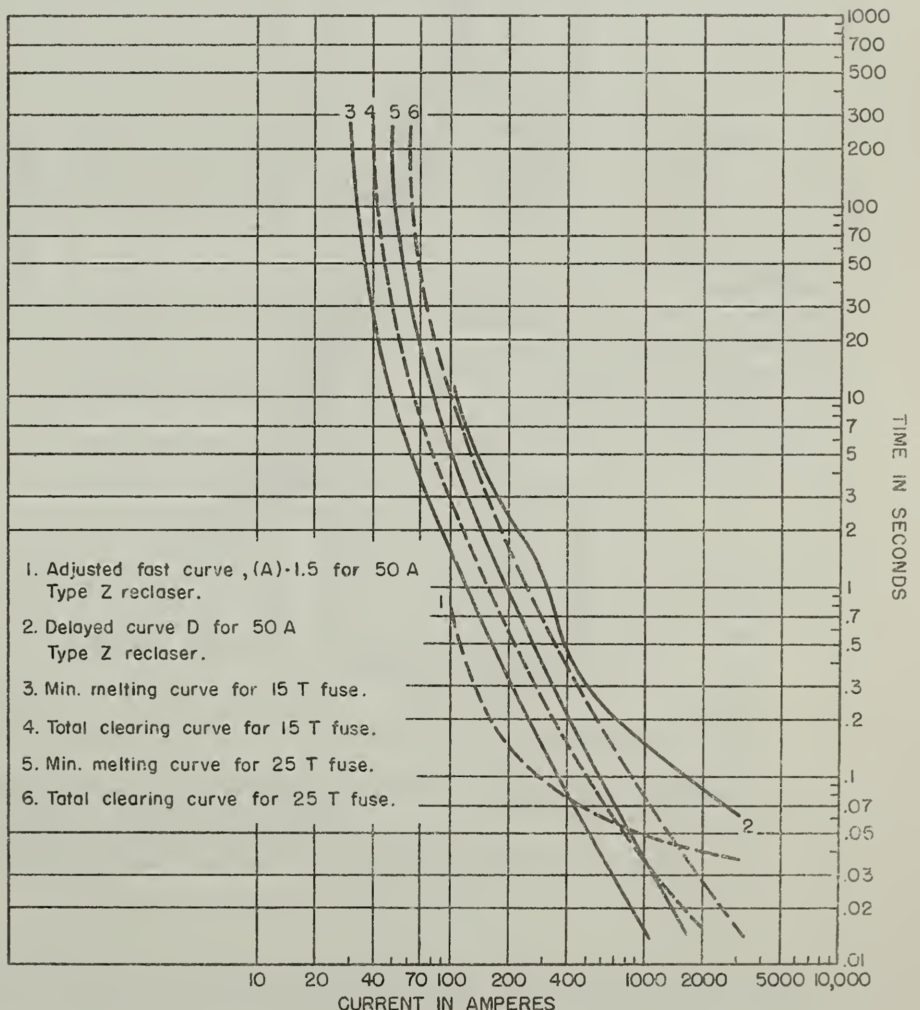


Figure 18. Coordination chart of 50a Type Z recloser and line fuses.

At ABC3', three single-phase, 70 ampere, Type Z reclosers are located with a sequence of 2A and 2D operations. The recloser fast time-current curve is shifted up by a factor of 1.5 for coordination with load-side fuses. The time-current curves are plotted in Figure 19. At ABC6, the maximum fault current is 892 amperes, the load current at A6 and BC6 is 20 amperes per phase. The minimum fault current for both feeders is 165 amperes (refer to Figure 14). Based on this information, three 30T fuses were selected for A6 and BC6. The fuses' minimum melt and total clearing curves are plotted in Figure 19. Examining Figure 19, the recloser will clear on its fast curve before the fuse link melts and the fuse will clear the fault before the recloser locks out for the range of available fault current. The same procedure is used for ABC7 and 7' and the time-current curves are plotted in Figure 19.

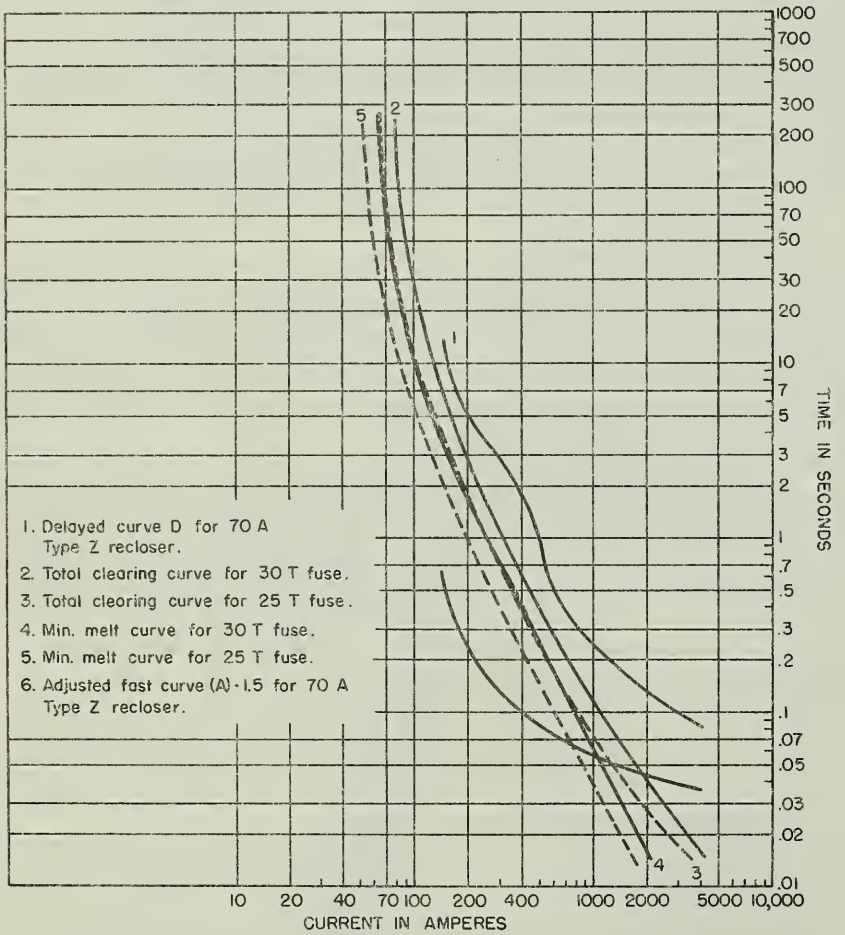


Figure 19. Coordination chart of 70a Type Z line recloser and line fuses.

F. Tabulation of Sectionalizing Devices

The sectionalizing devices are tabulated on the sample sectionalizing device schedule shown in Figure 20. The load current and fault current at each sectionalizing point are recorded in Figure 20 and the sectionalizing device ratings are checked against the respective load and fault currents.

SECTIONALIZING DEVICE SCHEDULE
SHEET __ OF __

System Designation: Any State, 19 Alpha		Substation or Metering Point Designation: Bartlett Sub. CKT	
Date	Prepared by	Installed Capacity	Source-Load Voltage: 115/12.5 - 7.2 kV
Instructions - See REA Bulletin 62-1	Circuit Breakers or Reclosers	Fuses or Sectionalizers	
Substation - Supply Side		80E, 3 Power Fuses	
Substation - Load Side	3 Ø, Type We, Recl.		
Distribution Lines			

Point	Load Current	Fault Current (1)		Existing Device				Proposed Device				Reason For Change (3)
		Max.	Min.	No.	Type (2)	Rating	G-Trip	No.	Type (2)	Rating	G-Trip	
High Side Sub	50	7168		-	-------	----	---	3	1 Ø Power	80E	--	
Load Side Sub	140	6188	200	-	-------	----	---	1	3 Ø, Type YE, ACR	280PT	200 A	
ABC1	20	3596	210	-	-------	----	---	3	Fuse	65T	---	
ABC2'	20	1353	201	-	-------	----	---	3	Fuse	50T	---	
ABC2	15	1353	201	-	-------	----	---	3	Fuse	50T	---	
ABC3	35	1030	107	-	-------	----	---	3	1 Ø, Type Z, ACR	50	---	
ABC3'	50	1030	155	-	-------	----	---	3	1 Ø, Type Z, ACR	70	---	
ABC4	15	599	35	-	-------	----	---	3	Fuse	25T	---	
ABC5	5	419.4	107	-	-------	----	---	3	Fuse	15T	---	
ABC5'	15	419.4	118	-	-------	----	---	3	Fuse	25T	---	
A6	20	573	165	-	-------	----	---	1	Fuse	30T	---	
BC6	20	771	165	-	-------	----	---	2	Fuse	30T	---	
ABC7	10	834	155					3	Fuse	25T		
ABC7'	20	834	170					3	Fuse	30T		

NOTES:
(1) Maximum at point - Minumum at end of controlled section with ___ ohms fault resistance
(2) ACR - Automatic Circuit Recloser , SECT - Sectionalizer
(3) IC - Interrupting Capacity , LC - Load Current , C - Coordination , NC - No Change , A - Additional Device

Figure 20. Tabulation of sectionalizing devices of sample problem.

CHAPTER VII

COMPLETION OF SECTIONALIZING STUDY AND INSTRUCTIONS TO OPERATING PERSONNEL

After making all calculations, selecting recloser settings (or sizes) and ratings, selecting fuses and sectionalizers, the Sectionalizing Study Report should be prepared. The selected apparatus for each feeder should be clearly indicated on a form similar to the one shown in Figure 20.

It should be understood that a theoretical study may not always give perfect results in practice. It is often not feasible to develop a system overcurrent protection scheme which will achieve perfectly coordinated sectionalizing for all possible contingencies. Since this means that compromises must be made, the engineer should clearly state in his report the location or theoretical problems where lack of coordination may exist and the rationale for making his decisions. He should also indicate his choice of fault resistance used in calculating minimum fault current. The report should caution the operating personnel against arbitrary changes in sectionalizing devices. Fuse links should be replaced by a link of the proper size and make, and changes in recloser size or settings should not be made without the consent of the system protection engineer. Indiscriminate changes in a sectionalizing study can render the overcurrent protection ineffective and may even subject lines and equipment to damaging conditions.

Distribution system protection should be based upon a total system concept, including the power supply. For this reason, close liaison between the power supplier, the system protection engineer, and the distribution system operating personnel or management is necessary. When any changes are made to the system such as additions or revisions of line, increase in substation capacity, or power supply changes, a supplementary sectionalizing study should be made to insure that the sectionalizing program is up to date and that ratings of interrupting devices are still adequate. The distribution system management must carefully make periodic checks of peak loads to insure that overloads of sectionalizing devices do not occur as loads grow.

APPENDIX A

VECTOR METHOD OF CALCULATING FAULT CURRENTS

A method for calculating fault currents has been devised which uses vectors instead of calculations. The vector method may save time, while it also offers a visual picture and permanent record of the fault currents, and provides a simple method for calculating such currents on new branch lines.

Information Required

The following information is necessary:

1. Total resistance and total reactance, for both the maximum and minimum fault current conditions, on the load side of the supply substation or at the metering point. It is necessary to know these resistance and reactance values for three-phase, line-to-line, and line-to-ground faults and they must be referred to the line-to-ground voltage of the system. See Chapter II, discussion on source impedance.

2. Location of sectionalizing points on a circuit diagram of the system.

3. Phasing, distances, and wire sizes between sectionalizing points and from the last sectionalizing points to the end of the most distant tap.

Description of Current Diagrams

The fault current calculations are made on current diagrams. Separate current diagrams are used for each fault current study and these are made a part of the sectionalizing study file. Sample current diagrams are available from REA for three-phase, line-to-line, and line-to-ground faults on 12.5/7.2 kV and 24.9/14.4 kV systems built to REA specifications. The current diagrams can be used for other system voltages, as explained later in this section.

Referring to the current diagram shown as Figure 21 in the sample problem, note that the background of the diagram is a rectangular coordinate system with resistance in ohms along the horizontal axis and reactance in ohms along the vertical axis. Superimposed upon the coordinate system there is a series of concentric quarter circles each circle indicating a value of short circuit current. Note that the current diagram is really the first quadrant of a current vector diagram with the line-to-ground voltage as the base voltage. Fault currents can be read on the circle at the intersection of the total resistance and the total reactance values of the circuit.

In the lower left-hand corner, there is a group of scales called "kilometer scales," each scale representing a different copper equivalent conductor size. The length of line in kilometers is marked along each scale, starting from zero on the left end of the scale. The position of each kilometer scale on the diagram and the calibration of each scale is governed by the per kilometer resistance and reactance values of lines built to REA specifications for each conductor size. The kilometer scales are based on average values of resistance and reactance for the various types of conductor. The scale to which each kilometer scale was drawn is the same as the scale of the rectangular coordinate system on the main part of the current diagram.

Use of Data Sheet

The short circuit current data sheet shown in Figure 25 of the sample problem may be used for tabulating the data necessary to plot the fault current points on the diagram, and for tabulating the maximum and minimum fault currents. Each sectionalizing point on the system, and the most distant points beyond the last sectionalizing devices, should be designated on a circuit diagram in accordance with REA Bulletin 60-1. Then the data necessary to plot the points on the current diagram should be tabulated in the first four columns of the form. After the points have been plotted on the current diagram, the fault currents at 7200 volts phase-to-ground as read on the current diagram can be tabulated into the appropriate columns.

Calculation of Fault Currents When System Voltage is Not 12.5/7.2 kV or 24.9/14.4 kV By Using Current Values Determined From 7200 Volt Current Diagrams

The fault current at any location on a system is directly proportional to the line-to-ground voltage. Suppose a fault current study is being made on a system whose voltage is 11.9/6.9 kV. The fault currents as read on the 7200 volt three-phase, line-to-line, and line-to-ground current diagrams must be multiplied by $\frac{6900}{7200}$ in order to obtain the actual fault current values.

If the line-to-ground voltage is not 7200 volts, multiply the fault current values read on the current diagram by the actual line-to-ground voltage/ 7200 Volts and tabulate the actual fault currents into the appropriate columns of the short circuit current data sheet.

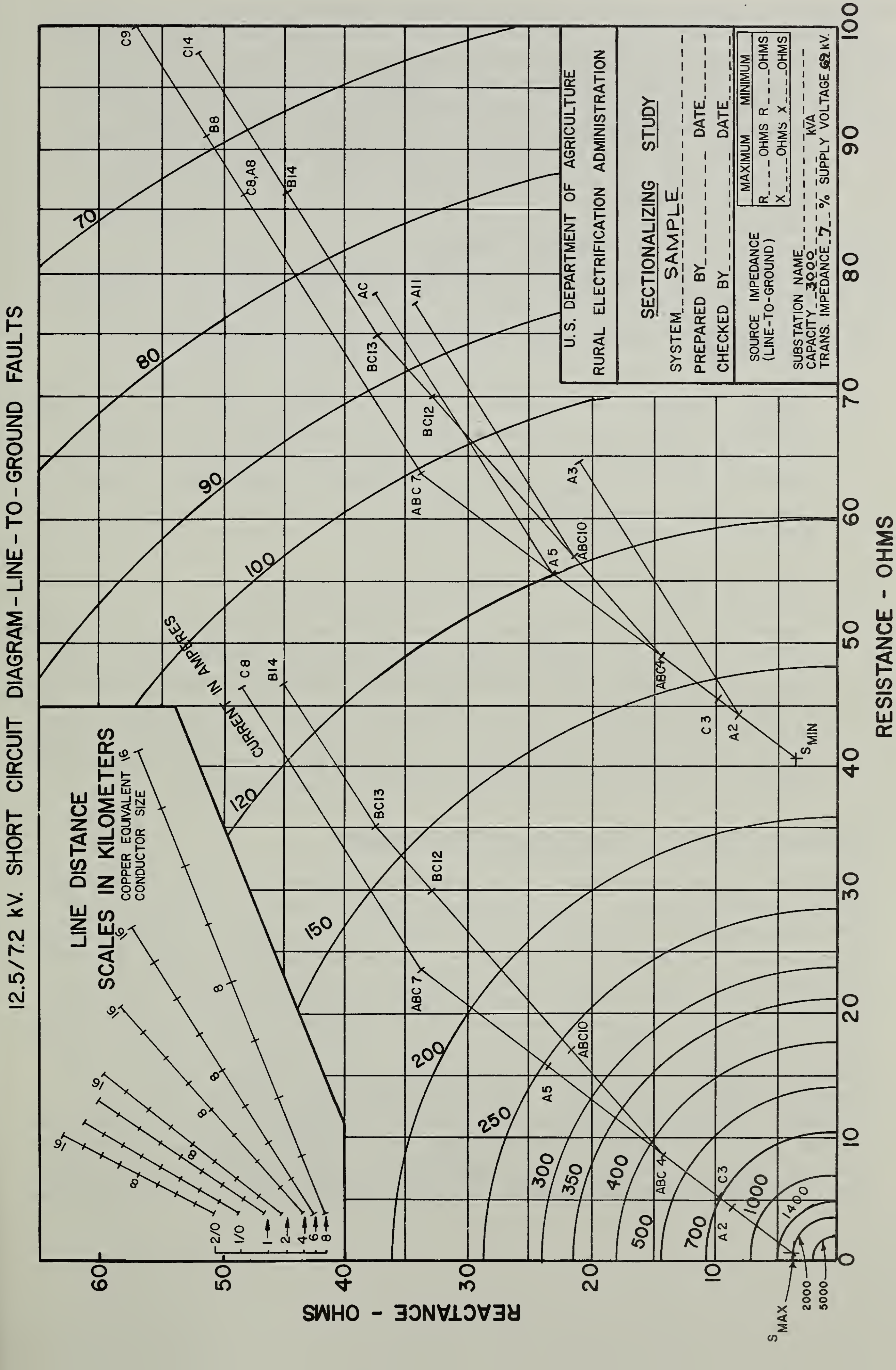


Figure 21. Short circuit diagram for sample problem using the vector method.

Procedure for Calculating Short Circuit Currents on Current Diagrams

1. On the current diagram for the type of fault being calculated, locate the point for the total impedance of the source and substation by laying off the resistance along the horizontal scale and the reactance along the vertical scale. Locate the total impedance for both the maximum and minimum conditions. For the minimum condition on line-to-ground faults, be sure to add in the assumed value of fault resistance, usually 40 ohms. Mark these two points $S_{max.}$ and $S_{min.}$

   By using two triangles or a drafting machine, draw a line from $S_{max.}$ and $S_{min.}$ to the right, parallel to the distance scale for the conductor size in the first section of line away from the substation.

2. Using a compass, or dividers, and the distance scale for the proper conductor size, set the instrument to the number of kilometers from the substation to the first sectionalizing point. Lay this distance off from $S_{max.}$ and $S_{min.}$ along the line drawn in step two. Letter these points the same as the corresponding point on the circuit diagram.

3. Read the short circuit currents on the circles.

4. Repeat the above procedure for the next sectionalizing point farther out on the system, except that the kilometer distance should be laid off from the last points plotted instead of from $S_{max.}$ and $S_{min.}$ If the next section is of a different conductor size, draw a new line on the diagram, parallel to the proper distance scale. Repeat until all points on the system, at which short circuit current values are desired, have been plotted on the diagram.

Distance Scales Not Given on Current Diagram

Distance scales are given on the current diagram for the most commonly used conductor sizes. In cases where there is not a distance scale for the conductor installed on the distribution line, a distance scale can easily be drawn on the diagram. It is necessary to know the resistance and reactance of the line in ohms per kilometer for the type of conductor used and for the type of fault being calculated. Pick any convenient point several centimeters to the left of the distance scales on the diagram. From this point, using the resistance scale on the diagram, lay off a distance to the right equal to the resistance of one kilometer of the line. From the point just located, lay off a distance vertically upward, equal to the reactance of one kilometer of the line. There will now be two legs of a right triangle, the hypotenuse of which is equal to the impedance of one kilometer of the line. Draw the hypotenuse and extend it upward to the right. The line drawn

will be the distance scale desired. Calibrate the scale in kilometers by marking off distances on the scale equal to the length of the hypotenuse of the small triangle. In order to obtain greater accuracy in plotting the distance scale, it is suggested that ten times the per-kilometer resistance and reactance values be used in laying off the triangle as explained above. Then subdivide the hypotenuse into ten parts.

Suggestion

A separate current diagram should be used for each substation on the system. In cases where one substation serves a large number of kilometers of line, and there are a large number of sectionalizing points, it is suggested that separate current diagrams be used for each one of the main feeders from the substation, in order to prevent confusion which may result from too many points on the same current diagram.

APPENDIX B

SIMPLIFIED METHOD FOR CALCULATING FAULT CURRENT

I. This appendix describes a simplified method for calculating fault current on 12.5/7.2 kV and 24.9/14.4 kV rural distribution systems.

While the results are not exact, the method is considered sufficiently accurate for the application of sectionalizing devices on distribution systems. The simplified method is not recommended for the selection of fuses or other sectionalizing devices on the source side of the substation. Except for this purpose and the conditions described in section three, the simplified method may be used as an alternate to the calculation or vector methods in this bulletin.

II. Sample Forms: The following sample forms are used in this method:

1. Nomogram for Determining Approximate Three-Phase and Line-to-Ground Maximum Fault Current at 12.5/7.2 kV Substations.
2. 12.5/7.2 kV Short Circuit Current Diagram Line-to-Ground Faults.
3. 12.5/7.2 kV Short Circuit Diagram Three-Phase Faults.
4. 12.5/7.2 kV Short Circuit Current Diagram Line-to-Line Faults.
5. Nomogram for Determining Approximate Three-Phase and Line-to-Ground Maximum Fault Current at 24.9/14.4 kV Substations.
6. 24.9/14.4 kV Short Circuit Current Diagram Line-to-Ground Faults.
7. 24.9/14.4 kV Short Circuit Current Diagram Three-Phase Faults.
8. 24.9/14.4 kV Short Circuit Current Diagram Line-to-Line Faults.

III. Substation Fault Current Nomograms

Maximum fault current at the substation bus may be found from nomograms as illustrated for the 12.5/7.2 kV case in Figure 22. The results are approximate since the assumption is made that the source impedance can be neglected.

This assumption is valid for most conditions. However, when the substation is supplied from a small generating plant or a transmission line of limited capacity, the source impedance may be substantial and the nomograms may yield much higher fault currents than actually exist.

As a general rule, therefore, these nomograms should be used only when the substation is supplied by a transmission line having a line-to-line voltage greater than 60 kV. For other conditions, the calculation

method given in the bulletin should be used for determining fault current.

There are exceptions to this rule. In the case of a short line of, for instance, 41.6 kV supplied from a large high voltage bus, this method will generally be satisfactory if the substation distribution voltage is 12.5/7.2 kV. On the other hand, a long radial 69 kV line serving a large substation may have a source impedance sufficiently large to cause an appreciable error. This error will be significant only in the maximum fault current at and near the substation and will be on the conservative side; that is, it may result in the selection of sectionalizing devices at the substation with larger interrupting capacity than necessary. It will not cause improper or inadequate sectionalizing. If accurate source impedances are known, the calculation method given in the bulletin may result in more economical sectionalizing. Complete instructions for calculating fault current are given on the nomograms.

IV. Short Circuit Current Diagrams

Each short circuit current diagram is a plot of Ohm's law. For a constant voltage, any combination of source and line impedances may be converted directly to short circuit current. The diagram is simplified further by adding impedances arithmetically rather than vectorially. While this is not a rigorous solution, the results should be sufficiently accurate for most purposes. Separate short circuit current diagrams are used for the three types of faults usually calculated: line-to-line, line-to-ground, and three phase. Figure 23 shows the line-to-ground short circuit diagram for 12.5/7.2 kV systems in reduced size. The line-to-line and three-phase short circuit diagrams are similar. Referring to Figure 23 note that fault currents are read on the left-hand scale. Proceeding to the right, there are two sets of three vertical lines. Each vertical line is designated as a phase of the circuit. The conductor line distance scales are at the lower right-hand corner of the form. The extreme right-hand vertical line is a current scale used only for extra long circuits. For such circuits, the impedance to the most distant point may exceed the limit of the short circuit current diagram. In this case, when the impedance reaches the upper limit of the diagram, the scale is reversed or folded back and the circuit impedance values continue downward. The short circuit current values are then read on the right-hand scale for the folded portion of the line.

To use the short circuit current diagrams the following information is needed:

1. The maximum fault current at the substation for all three types of faults. This may be obtained from the substation nomogram or by the calculation method.

2. Location of sectionalizing points on a circuit diagram of the system.

3. Phasing, distances and wire sizes between sectionalizing points and from the last sectionalizing point to the most distant point.

V. Sample Problem:

Refer to Figure 24 for the sample circuit diagram and to Figure 25 for the tabulation of conductor sizes, phasing, and distances. The only other information needed is the substation transformer impedance which in the example is assumed to be 7 percent as read on the transformer nameplate.

On the substation fault current nomogram, Figure 22, draw a line between 7 percent impedance on the left-hand scale and the transformers three-phase kVA rating, 3000 kVA on the right-hand scale. The maximum line-to-ground and three-phase fault currents are read at 1950 amperes on the middle scale. Multiply this value by 0.867 to find the line-to-line substation fault current of 1690 amperes.

The short circuit current diagram shown in Figure 23 will be used to illustrate the procedure for determining maximum and minimum line-to-ground faults. The calculation of line-to-line and three-phase faults follows a similar procedure.

Locate 1950 amperes on the left side of the fault current scale and read the minimum fault current of 175 amperes on the right side of the same scale. Draw a horizontal line from this point to the right cutting the three vertical lines representing the circuit. Label this line "Sub" as shown in Figure 23.

The first point is A2, on a No. 2 copper equivalent conductor line, 4.8 kilometers from the substation. With a pair of dividers, transfer this distance from the line distance scale for No. 2 conductor to the vertical line representing phase A starting from the line labeled "Sub." Draw a small line through phase "A" as shown and label it A2. On the current scale read 790 amperes maximum, 163 amperes minimum.

The next point is C3 on phase C, one kilometer from point A2. Conductor size between points is No. 2. Again with the divider, transfer this value from the line distance scale to the vertical line labeled phase C starting from point A2. Draw a small line through phase C as shown and read on the current scale 650 amperes maximum, 156 amperes minimum.

Continue this process for each sectionalizing point on the circuit. For V-phase designated points draw a horizontal line through the two phases represented. For three-phase designated points, draw a line through all three phases. This will assist in locating points when needed.

When the fault currents have been determined for line-to-ground faults, the process is repeated for line-to-line and three-phase faults. The maximum and minimum values may then be transferred to the short circuit current data sheet for future reference.

INSTRUCTIONS:

1. DETERMINE PERCENT IMPEDANCE FROM TRANSFORMER NAME PLATE.
2. LOCATE THIS VALUE ON LEFT HAND SCALE AND DRAW A STRAIGHT LINE TO POINT ON RIGHT HAND SCALE EQUAL TO SUBSTATION THREE PHASE KVA.
3. READ MAXIMUM THREE PHASE AND LINE-TO-GROUND FAULT CURRENT ON CENTER SCALE.
4. FOR LINE-TO-LINE FAULT CURRENT, MULTIPLY FAULT CURRENT BY 0.867.

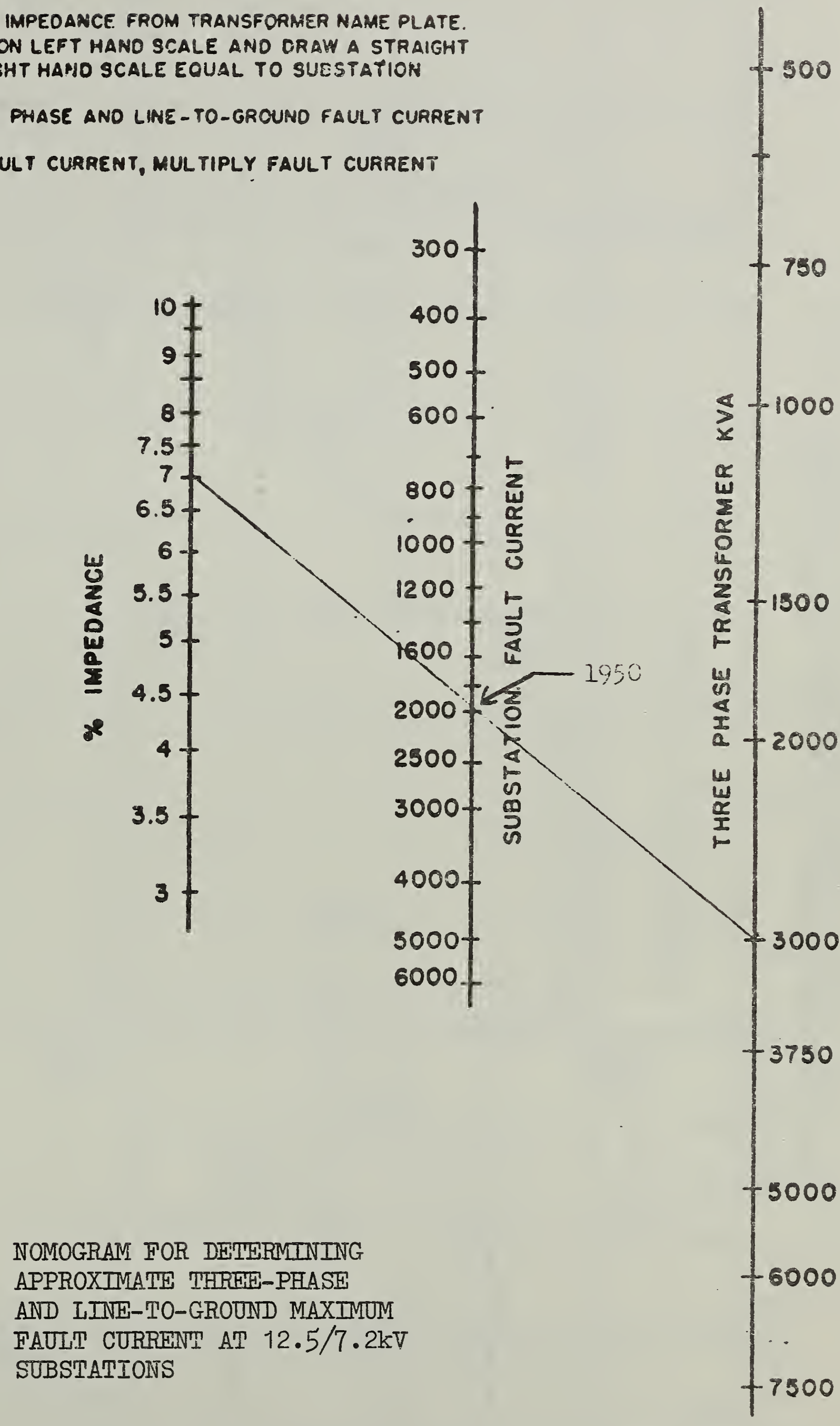


Figure 22. Substation fault current nomogram

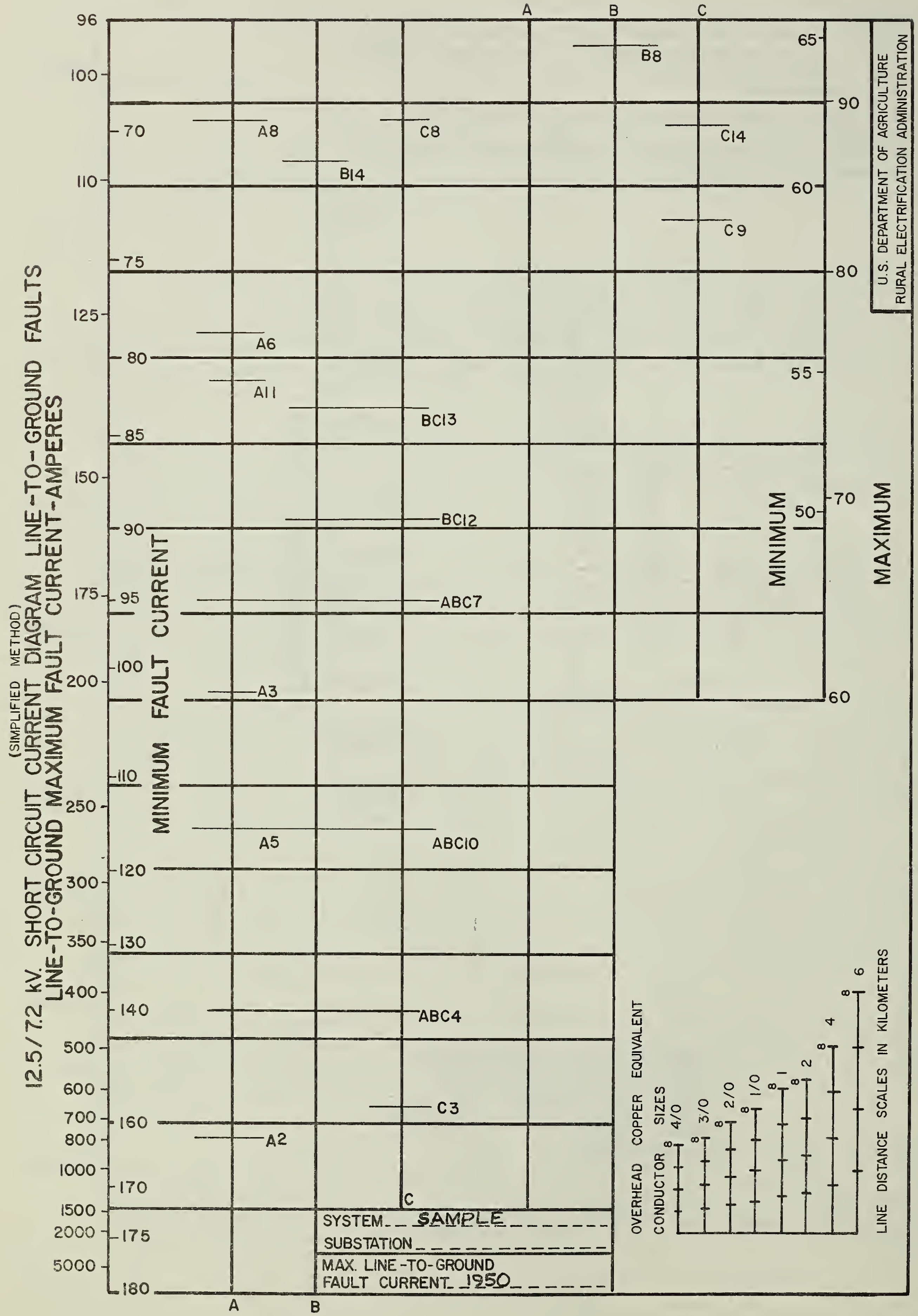


Figure 23. Short circuit diagram for line-to-ground faults, on 12.5/ 7.2 kV systems, for sample problem using simplified method.

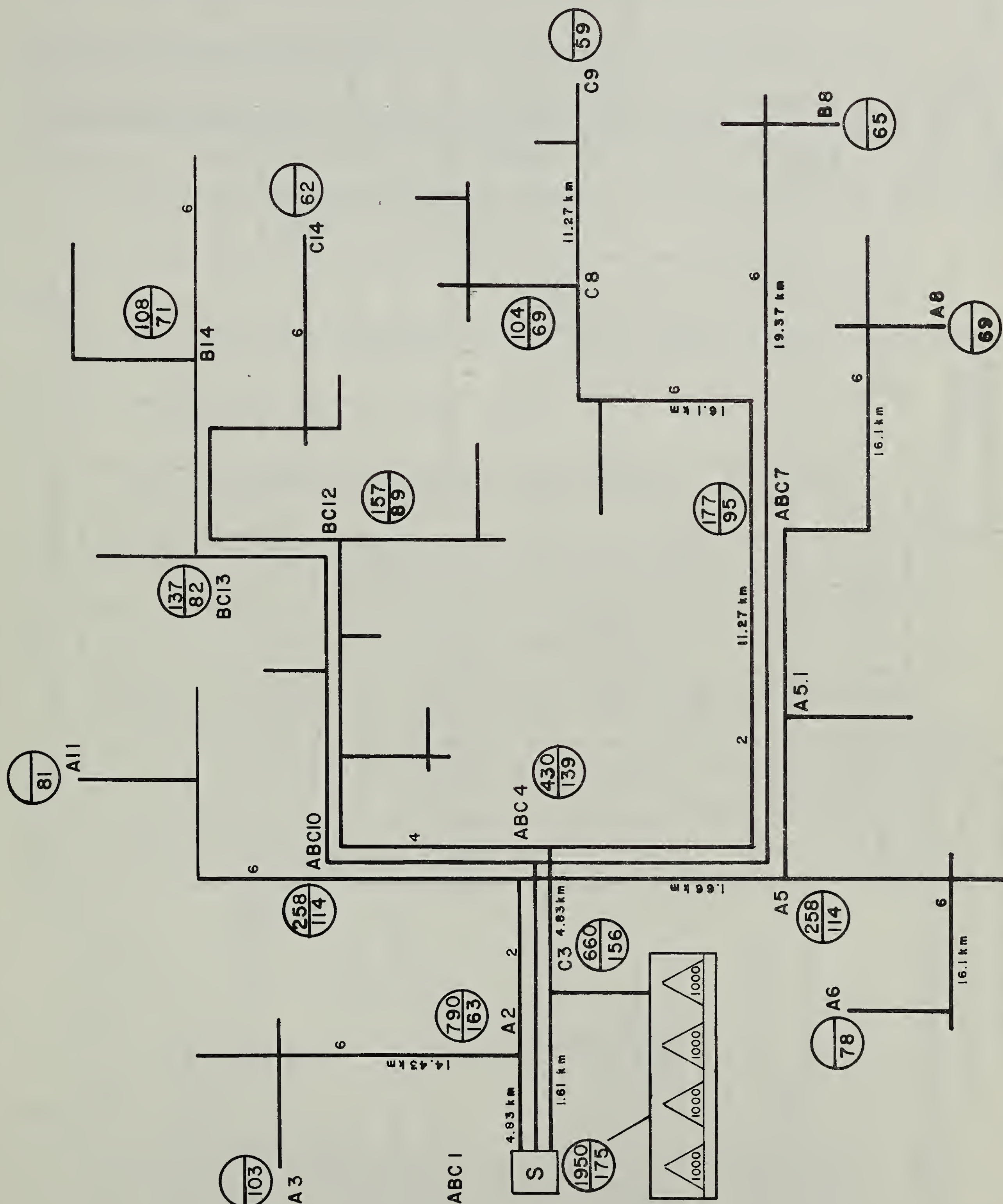


Figure 24. Circuit diagram for sample problem using simplified method.

U.S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

SHORT CIRCUIT CURRENT DATA SHEET

DATE	SHEET OF SHEETS
SYSTEM DESIGNATION SAMPLE	SYSTEM LINE-TO-GR. VOLTAGE 7.2KV
PREPARED BY	CHECKED BY

INSTRUCTIONS -*See REA Bulletin 61-2 and supplement*

1. POINT	SUB	A2	A3	C3	ABC4	A5	A6	ABC7	C8	C9	B8	A8		
2. PRECEDING POINT ON LINE TOWARD SUBSTATION		SUB	A2	A2	C3	ABC4	A5	A5	ABC7	C8	ABC7	ABC7		
3. KILOMETERS FROM PREVIOUS POINT ON LINE TOWARD SUBSTATION		4.83	14.48	1.61	4.83	1.66	16.1	11.27	16.1	11.27	19.37	16.1		
4. COPPER CONDUCTIVITY SIZE SECTION FROM PREVIOUS POINT		2	6	2	2	2	6	2	6	6	6	6		
5. TYPE OF FAULT CALCULATED			LINE - TO - GROUND											
6. MAXIMUM FAULT CURRENT, READ ON CURRENT DIAGRAM (SIMPLIFIED METHOD)	1950	790	–	660	430	258	–	177	104	–	–	–		
7. MINIMUM FAULT CURRENT, READ ON CURRENT DIAGRAM (SIMPLIFIED METHOD)	175	163	103	156	139	114	78	95	69	59	65	69		
8. MAXIMUM FAULT CURRENT (VECTOR METHOD)	1950	800	–	655	425	258	–	175	108	–	–	–		
9. MINIMUM FAULT CURRENT (VECTOR METHOD)	175	160	106	153	141	118	83	100	73	62	68	73		
1. POINT	ABC10	ALL	BC12	BC13	C14	B14								
2. PRECEDING POINT ON LINE TOWARD SUBSTATION	ABC4	ABC10	ABC10	BC12	BC13	BC13								
3. MILES FROM PREVIOUS POINT ON LINE TOWARD SUBSTATION	5	9	8	3	10	5								
4. COPPER CONDUCTIVITY SIZE SECTION FROM PREVIOUS POINT	4	6	4	4	6	6								
5. TYPE OF FAULT CALCULATED			LINE - TO - GROUND											
6. MAXIMUM FAULT CURRENT, READ ON CURRENT DIAGRAM (SIMPLIFIED METHOD)	258	–	157	137	–	108								
7. MINIMUM FAULT CURRENT, READ ON CURRENT DIAGRAM (SIMPLIFIED METHOD)	114	81	89	82	62	71								
8. MAXIMUM FAULT CURRENT (VECTOR METHOD)	258	–	160	140	–	110								
9. MINIMUM FAULT CURRENT (VECTOR METHOD)	118	85	92	86	65	74								

**Items 8 and 9 are to be used only when system voltage in not same as on short circuit current diagrams (See instructions).*

Figure 25. Short circuit current data sheet, for sample problem using simplified method.

APPENDIX C

SUPPLEMENTARY FORMULAS FOR FAULT CURRENT CALCULATIONS (METRIC)

A. Impedance of REA-Type Lines

The general expression for the line impedance, Z_L, in ohms per circuit kilometer of a multigrounded single-phase line is as follows:

$$Z_L = Z_{11} - \frac{(Z_{IN})^2}{Z_{NN}} + \frac{(1 - \mu)}{S} - Z_{NG}$$

Where:

Z_{11} (the self-impedance of the phase wire in ohms per kilometer)

$Z_{11} = (R_e + R_1) + j\,(X_e + X_1)$.

R_e =(.000988)(f) where f is the frequency in hertz.

R_1 = effective resistance of phase wire in ohms per kilometer.

The value of R_1 may be obtained from the manufacturers' tables or electrical handbooks.

X_e = $.001447\ (f)\ (\log_{10} 4{,}665{,}500 \frac{P}{f})$ where P is ground resistivity in meter-ohms. A value of 100 meter-ohms is generally assumed if it is not otherwise specified.

X_1 = inductive reactance of the phase wire in ohms per kilometer for 0.3048 meter spacing. Values of X_1 are obtainable from manufacturers' tables or electrical handbooks.

or Z_{11} maybe defined as:

$$Z_{11} = R_1 + .059 + j\ .17365\ \mathrm{Log}_{10} \frac{De}{GMRa}$$

Where:

De $= \left((658.36)\ (P/60)^{\frac{1}{2}}\right)$

P = earth resistivity in meter-ohms

GMRa = Geometric mean radius of the phase conductor in meters obtained from the manufacturers' tables or electrical handbooks.

Z_{NN} (the self impedance of the neutral wire in ohms per kilometer)

$= (R_e + R_N) + j\ (X_e + X_N).$

R_e and X_e same as in Z_{11} above

R_N = effective resistance of neutral wire in ohms per kilometer. This value is available from manufacturers' data or electrical handbooks.

X_N = inductive reactance of the neutral wire expressed in ohms per kilometer for one .3048 meter spacing. Its value is available in manufacturers' data and in handbooks.

or Z_{NN} maybe defined as:

$$Z_{NN} = R_N + .059 + j\ .17365\ \mathrm{Log}_{10} \frac{De}{GMRn}$$

Where:

GMRn = Geometric mean radius of the neutral conductor in meters obtained from the manufacturers' tables or electrical handbooks.

$$ZIN = R_e + j\ (X_e - X_D)$$

R_e and X_e same as in Z_{11} above

$$X_D = \frac{(6.283)(f)}{1000} (0.741 \log_{10} (D)(3.281))$$

D is the spacing between phase and neutral wire in meters.

X_D = 0.1682, for D = 1.22 (Standard REA single-phase spacing) and f = 60 hertz.

$$Z_{NG} = R_g\ Z_{NN}\ (1 - \mu)\ \tanh \lambda S.$$

$$R_g = \frac{R}{n}$$

R = resistance per neutral wire ground in ohms.

n = number of grounds per kilometer

$$\mu = \frac{Z_{IN}}{Z_{NN}} \qquad \lambda = \frac{Z_{NN}}{R_g}$$

S = length of circuit in kilometers from power source.

The term $\left(\frac{1-\mu}{S}\right) \cdot Z_{NG}$ in the general expression of the line impedance, "Z_L", is a corrective factor which depends on the line characteristics and the length "S" of the line. This factor, for "S" equal to or greater than 10, becomes negligible. When there are no grounds on the neutral other than at the source, which is the actual case when "S" is very small, the impedance, "Z_L", becomes the same as that of a metallic single-phase circuit.

For two-phase wires and neutral ("V" circuit)

The Vee phase voltage equations are:

$$Ea = Ia\ Zaa + Ib\ Zab + In\ Zan$$

$$Eb = Ia\ Zba + Ib\ Zbb + In\ Zbn$$

$$En = Ia\ Zna + Ib\ Znb + In\ Znn$$

$$Z\ self = R_1 + .059 + j\ .17365 \log 10 \frac{De}{GMR\ cond.}$$

$$Z\ mutual = .059 + j\ .17365 \log 10 \frac{De}{dxy}$$

Z self = the self impedance of the conductor with ground return expressed in ohms per kilometer.

Z mutual = the mutual impedance between conductors x and y with ground return expressed in ohms per mile.

GMR cond = geometric mean radius of the conductor in meters.

$$De = 658.36 \times \left(\frac{P}{60}\right)^{\frac{1}{2}}$$

P = earth resistivity in meter-ohms.

dxy = distance between conductors x and y in meters.

The procedure to solve the impedance of phase A and B is to calculate phase currents IA and IB assuming the phase voltages Ea and Eb are equal in magnitude and 120º out of phase. The current IA and IB can be solved by hand, using determinants or matrices. However, since vee phase lines involve 3 equations with all terms being vector quantities, it is suggested that the phase current Ia and Ib be solved by the iterative technique, using a digital computer.

With Ia and Ib known the impedance can be calculated as follows:

$$Za = \frac{E_a}{I_a} \qquad Zb = \frac{E_b}{I_b}$$

For three-phase wires and neutral

Assume balanced conditions (no ground current).

$$Z_L = r_c + j0\ .17365 \log_{10} \frac{G.M.D}{GMR\ cond.} \text{ for } f = 60 \text{ hertz.}$$

Where: Z_L = impedance of line in ohms per meter

r_c = resistance of conductor

G.M.D. = geometric mean spacing in meters

G.M.D. = $\sqrt[3]{D_1 D_2 D_3}$ for 3 conductors

GMR cond. = geometric mean radius of conductor in meters.

B. Formulas for Fault Currents

1. Three-phase fault.

$$I_a = I_b = I_c = \frac{E}{(Z_1) + Z_f}$$

2. Line-to-ground fault on phase a.

$$I_a = \frac{E}{\frac{Z_1 + Z_2 + Z_0}{3} + Z_f}$$

$$I_b = I_c = 0$$

3. Line-to-line fault between phases b and c.

$$I_a = 0$$

$$I_c = -I_b = \frac{\sqrt{3}\ (E)}{(Z_1 + Z_2) + Z_f}$$

where:

E = Line-to-ground voltage

Z_1 = Positive phase sequence impedance

Z_2 = Negative phase sequence impedance

Z_0 = Zero phase sequence impedance

Z_f = Fault impedance

I_a, I_b, I_c, currents in a, b and c phases.

C. Delta-Wye Transformer Bank Current Conversion Formulas.

1. Three-phase fault

$$I_{sa} = I_{sc} = \sqrt{3}\ (N)\ (I_L)$$

2. Line-to-ground fault

$$I_{sa} = I_{sb} = (N)\ (I_L)$$

3. Line-to-line fault

$$I_{sa} = 2\ (N)\ (I_L)$$

$$I_{sb} = I_{sc} = (N)\ (I_L)$$

where:

I_{sa}, I_{sb}, I_{sc}, Line current in phases a, b and c on delta (supply) side.

I_L = fault current on wye (load) side.

N = Transformer turns ratio

$$N = \frac{E_L}{E_{s\ (L-L)}} \quad \text{for delta wye Bank}$$

D. Decrement of Positive Sequence Current in Alternators.

$$T'_d = \frac{X'_d}{X_d}\ (T_{do}) \text{ for circuit having negligible resistance}$$

$$T'_d = \frac{X'_d\ X_q + r^2}{X_d\ X_q + r^2}\ T_{do} \text{ for circuit with resistance}$$

where:

T'_d = Transient time constant

X'_d = Direct axis transient reactance (including line and machine)

X_q = quadrature axis synchronous reactance

X_d = direct axis synchronous reactance (including machine and line)

r = resistance of machine and line

T_{do} = open circuit time constant

$$\text{Then } I' = (I'_i - I)\,(e)^{\left(\frac{-t}{T'_d}\right)} + I$$

Where:

I' = positive sequence transient current at anytime

I'_i = initial transient current

I = sustained short circuit current (from synchronous impedance)

e = 2.7183

(This neglects the subtransient value and the action of the voltage regulator)

E. <u>Percent and Per Unit Formulas</u>.

$$(\%\ \text{impedance}) = \frac{\text{ohms (kVA)}}{(\text{kV})^2\ (10)}$$

$$\text{ohms} = \frac{(\%\ \text{impedance})\ (\text{kV})^2\ (10)}{\text{kVA}}$$

If kVA is per phase, kV must be the line-to-ground value.

If kVA is total, kV must be the line-to-line value.

$$\text{per unit impedance} = \frac{\text{Percent impedance}}{100}$$

To convert ohmic values from one voltage base to another, multiply by the square of the ratio of the line-to-ground voltages. (See above formulas.)

APPENDIX D

SUPPLEMENTARY FORMULAS FOR FAULT CURRENT CALCULATIONS (CUSTOMARY)

A. Impedance of REA-Type Lines

The general expression for the line impedance, Z_L, in ohms per circuit mile of a multigrounded single-phase line is as follows:

$$Z_L = Z_{11} - \frac{(Z_{IN})^2}{Z_{NN}} + \frac{(1 - \mu)}{S} - Z_{NG}$$

Where:

Z_{11} (the self-impedance of the phase wire in ohms per mile)

$Z_{11} = (R_e + R_1) + j\,(X_e + X_1)$.

R_e = (0.00159)(f) where f is the frequency in hertz.

R_1 = effective resistance of phase wire in ohms per mile. The value of R_1 may be obtained from the manufacturers' tables or electrical handbooks.

X_e = $(0.002328)\,(f)\,(\log_{10} 4{,}665{,}500 \frac{P}{f})$ where P is ground resistivity in meter-ohms. A value of 100 meter-ohms is generally assumed if it is not otherwise specified.

X_1 = inductive reactance of the phase wire in ohms per mile for one foot spacing. Values of X_1 are obtainable from manufacturers' tables or electrical handbooks.

or Z_{11} maybe defined as:

$$Z_{11} = R_1 + .095 + j\ .2794\ \mathrm{Log}_{10} \frac{De}{GMRa}$$

Where:

$De = 2160\ (P/60)^{\frac{1}{2}}$

P = earth resistivity in meter-ohms

GMRa = Geometric mean radius of the phase conductor in feet obtained from the manufacturers' tables or electrical handbooks.

Z_{NN} (the self impedance of the neutral wire in ohms per mile)

$= (R_e + R_N) + j\,(X_e + X_N)$.

R_e and X_e same as in Z_{11} above

R_N = effective resistance of neutral wire in ohms per mile. This value is available from manufacturers' data or electrical handbooks.

X_N = inductive reactance of the neutral wire expressed in ohms per mile for one foot spacing. Its value is available in manufacturers' data and in handbooks.

or Z_{NN} maybe defined as:

$$Z_{NN} = R_N + .095 + j\ .2794\ \text{Log}_{10} \frac{De}{GMRn}$$

Where:

GMRn = geometric mean radius of the neutral conductor in feet obtained from the manufacturers' tables or electrical handbooks.

$$Z_{IN} = R_e + j\ (X_e - X_D)$$

R_e and X_e same as in Z_{11} above

$$X_D = \frac{(6.283)}{1000}(f)(0.741 \log_{10} D)$$

D is the spacing between phase and neutral wires in feet.

X_D = 0.1682, for D = 4 (standard REA single-phase spacing) and f = 60 hertz.

$$Z_{NG} = R_g\ Z_{NN}\ (1 - \mu)\ \tanh\ S.$$

$$R_g = \frac{R}{n}$$

R = resistance per neutral wire ground in ohms.

n = number of grounds per mile.

$$= \frac{Z_{IN}}{Z_{NN}}$$

$$= \frac{Z_{NN}}{R_g}$$

S = length of circuit in miles from power source.

The term $\left(\frac{1-\mu}{S}\right)(Z_{NG})$ in the general expression of the line impedance, "Z_L", is a corrective factor which depends on the line characteristics and the length "S" of the line. This factor, for "S" equal to or greater than 10, becomes negligible. When there are no grounds on the neutral other than at the source, which is the actual case when "S" is very small, the impedance, "Z_L", becomes the same as that of a metallic single-phase circuit.

For two-phase wires and neutral ("V" circuit)

The Vee phase voltage equations are:

$$Ea = Ia\ Zaa + Ib\ Zab + In\ Zan$$

$$Eb = Ia\ Zba + Ib\ Zbb + In\ Zbn$$

$$En = Ia\ Zna + Ib\ Znb + In\ Znn$$

$$Z\ self = R_1 + .095 + j\ .2794\ \log 10\ \frac{De}{GMR\ cond.}$$

$$Z\ mutual = .095 + j\ .2794\ \log 10\ \frac{De}{dxy}$$

Z self = the self impedance of the conductor with ground return expressed in ohms per mile.

Z mutual = the mutual impedance between conductors x and y with ground return expressed in ohms per mile.

GMR cond = geometric mean radius of the conductor in feet.

$$De = 2160 \times \left(\frac{P}{60}\right)^{\frac{1}{2}}$$

P = earth resistivity in meter-ohms.

dxy = distance between conductors x and y in feet.

The procedure to solve the impedance of phase A and B is to calculate phase currents IA and IB assuming the phase voltages Ea and Eb are equal in magnitude and 120° out of phase. The current IA and IB can be solved by hand, using determinants or matrices. However, since vee phase lines involve 3 equations with all terms being vector quantities, it is suggested that the phase current Ia and Ib be solved by the iterative technique, using a digital computer.

With Ia and Ib known the impedance can be calculated as follows:

$$Za = \frac{E_a}{I_a} \qquad Zb = \frac{E_b}{I_b}$$

For three-phase wires and neutral.

Assume balanced conditions (no ground current).

$$Z_L = r_c + j0.2794 \log_{10} \frac{\text{G.M.D.}}{\text{GMR cond.}} \quad \text{for } f = 60 \text{ hertz}$$

where:

Z_L = impedance of line in ohms per mile per phase

r_c = resistance of conductor in ohms per mile

G.M.D. = geometric mean spacing in feet

G.M.D. = $\sqrt[3]{D_1 D_2 D_3}$ for 3 conductors

GMR cond. = geometric mean radius of conductor in feet

B. Formulas for fault currents

1. Three-phase fault.

$$I_a = I_b = I_c = \frac{E}{(Z_1) + Z_f}$$

2. Line-to-ground fault on phase a.

$$I_a = \frac{E}{\dfrac{Z_1 + Z_2 + Z_0}{3} + Z_f}$$

$$I_b = I_c = 0$$

3. Line-to-line fault between phases b and c.

$$I_a = 0$$

$$I_c = -I_b = \frac{(\sqrt{3})(E)}{(Z_1 + Z_2) + Z_f}$$

where:

E = Line-to-ground voltage

Z_1 = Positive phase sequence impedance

Z_2 = Negative phase sequence impedance

Z_0 = Zero phase sequence impedance

Z_f = Fault impedance

I_a, I_b, I_c, currents in a, b and c phases

C. Delta-Wye Transformer Bank Current Conversion Formulas

1. Three-phase fault

$I_{sa} = I_{sc} = \sqrt{3}\,(N)\,(I_L)$

2. Line-to-ground fault

$I_{sa} = I_{sb} = (N)\,(I_L)$

3. Line-to-line fault

$I_{sa} = 2\,(N)\,(I_L)$

$I_{sb} = I_{sc} = (N)\,(I_L)$

where:

I_{sa}, I_{sb}, I_{sc}, Line current in phases a, b and c on delta (supply) side.

I_L = fault current on wye (load) side

N = Transformer turns ratio

$N = \dfrac{E_L}{E_{s(L-L)}}$ for delta wye Bank

D. Decrement of Positive Sequence Current in Alternators

$T'_d = \dfrac{X'_d}{X_d}\,(T_{do})$ for circuit having negligible resistance

$T'_d = \dfrac{X'_d\,X_q + r^2}{X_d\,X_q + r^2}\,T_{do}$ for circuit with resistance

where:

T'_d = Transient time constant

X'_d = Direct axis transient reactance (including line and machine)

X_q = quadrature axis synchronous reactance

X_d = direct axis synchronous reactance (including machine and line)

r = resistance of machine and line

T_{do} = open circuit time constant

$$\text{Then } I' = (I'_i - I)\,(e)^{\left(\frac{-t}{T'_d}\right)} + I$$

where:

I' = positive sequence transient current at any time

I'_i = initial transient current

I = sustained short circuit current (from synchronous impedance)

e = 2.7183

(This neglects the subtransient value and the action of the voltage regulator)

E. Percent and Per Unit Formulas

$$(\%\text{ impedance}) = \frac{\text{ohms (kVA)}}{(\text{kV})^2\ (10)}$$

$$\text{ohms} = \frac{(\%\text{ impedance})\ (\text{kV})^2\ (10)}{\text{kVA}}$$

If kVA is per phase, kV must be the line-to-ground value.

If kVA is total, kV must be the line-to-line value.

$$\text{per unit impedance} = \frac{\text{Percent impedance}}{100}$$

To convert ohmic values from one voltage base to another, multiply by the square of the ratio of the line-to-ground voltages. (See above formulas.)

APPENDIX E

TRANSFORMER TIME-CURRENT DAMAGE CURVES

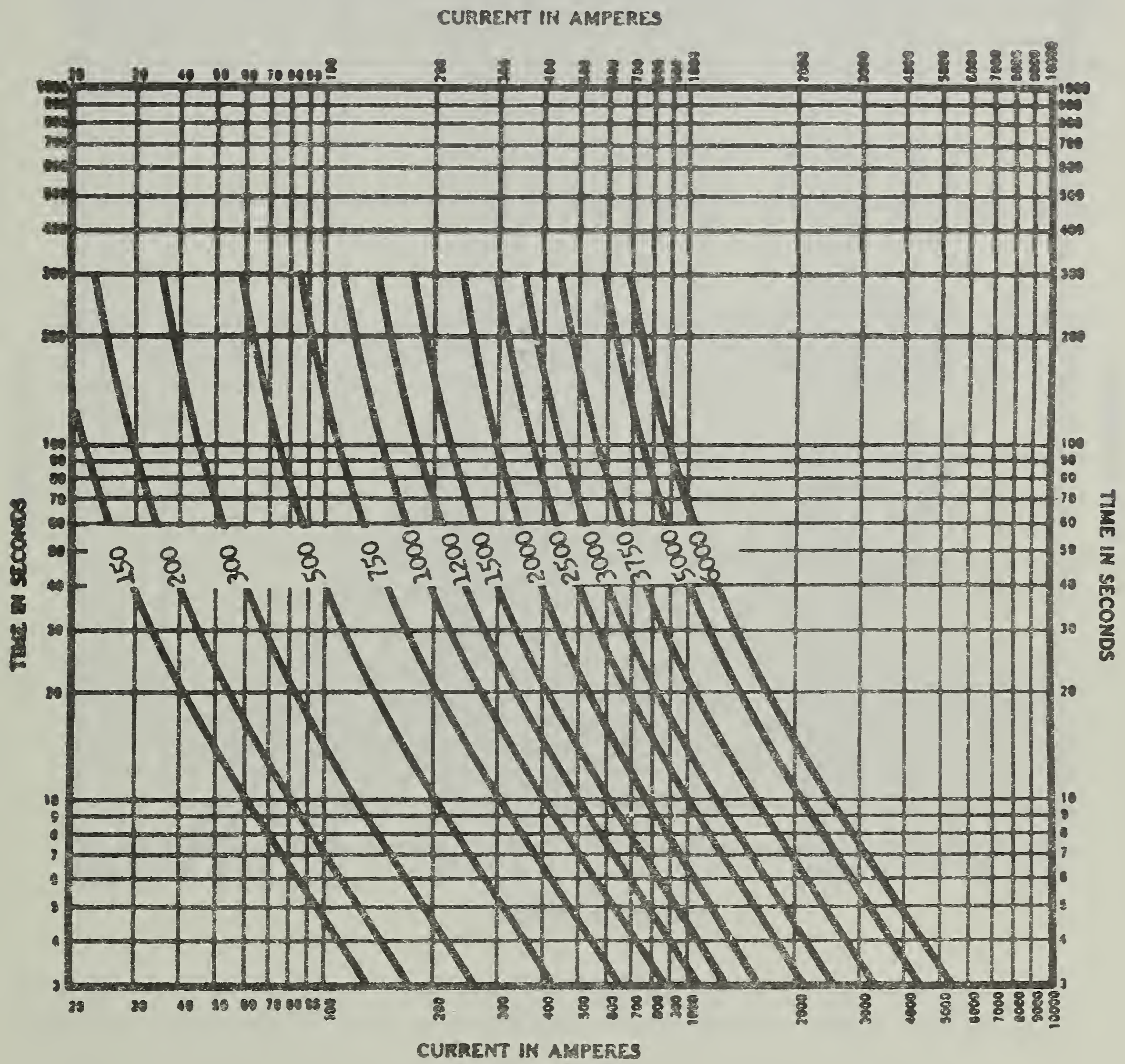


Figure 26

Three-phase 7200 volt transformer permissible short time loading curves for use only in connection with application of overcurrent protective devices when specific information applicable to individual transformers is not available. For other line-to-ground voltage N, multiply ampere scale by $\frac{7200}{N}$. Use these curves with caution!

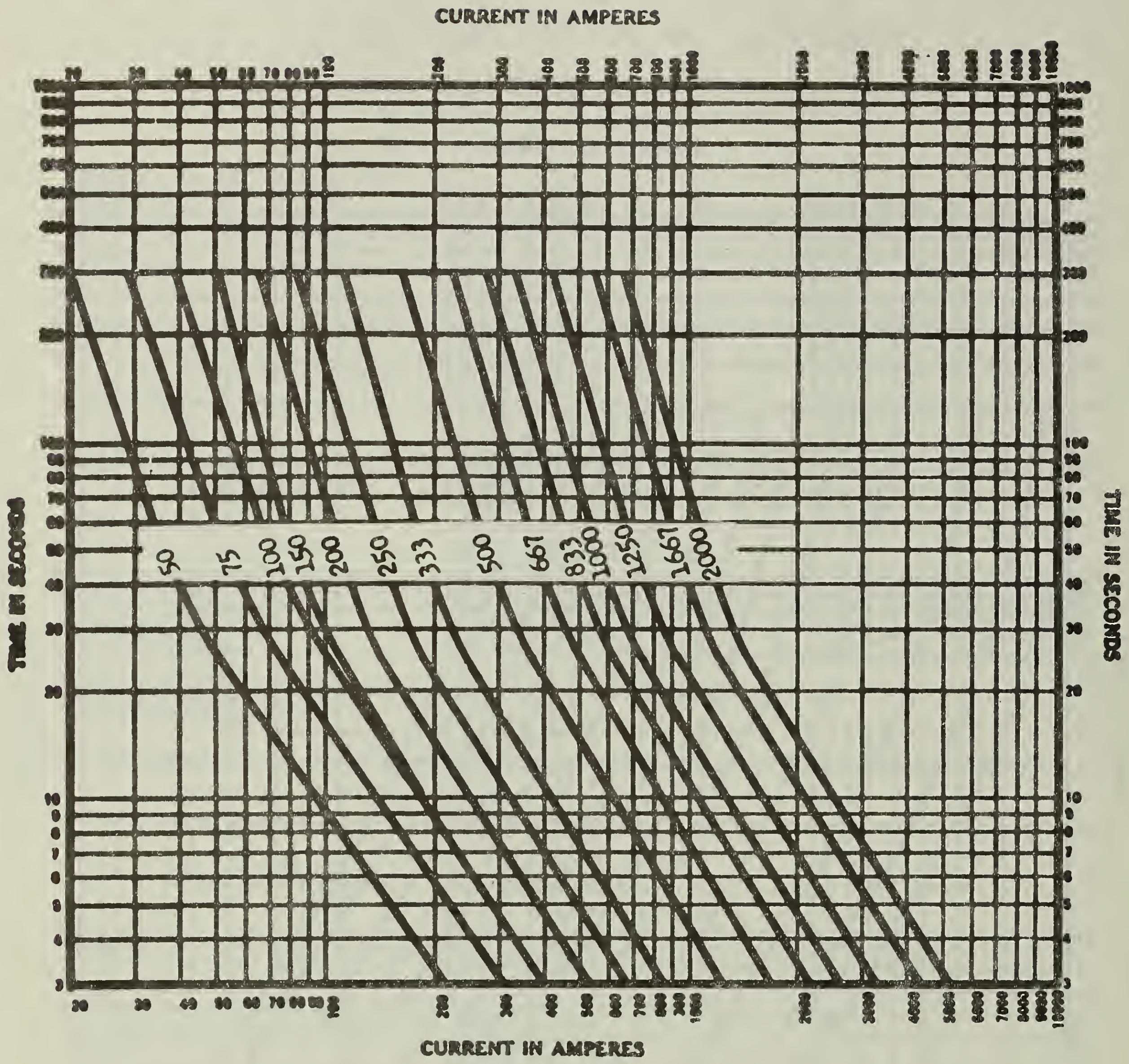


Figure 27

Single-phase 7200 volt transformer permissible short time loading curves for use only in connection with application of overcurrent protective devices when specific information applicable to individual transformers is not available. For other line-to-ground voltage N, multiply ampere scale by $\frac{7200}{N}$. Use these curves with caution!

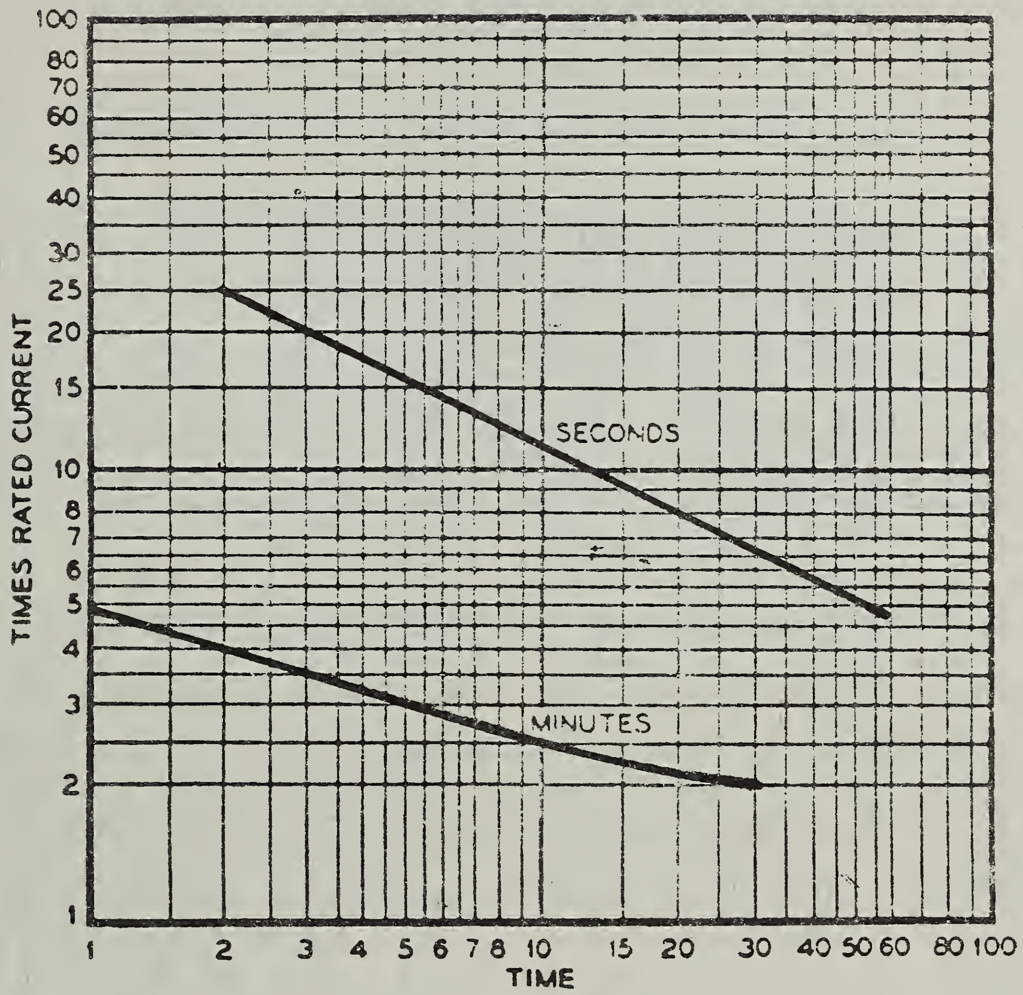


Figure 28

Substation transformers time-current damage curve. Short time loads following full load oil-immersed transformers. (ANSI C57.92)

The times rated current must be based on the equivalent self-cooled rating for other than self-cooled or water-cooled transformers.

APPENDIX F

TIME-CURRENT DAMAGE CURVES FOR BARE STRANDED ACSR CONDUCTOR

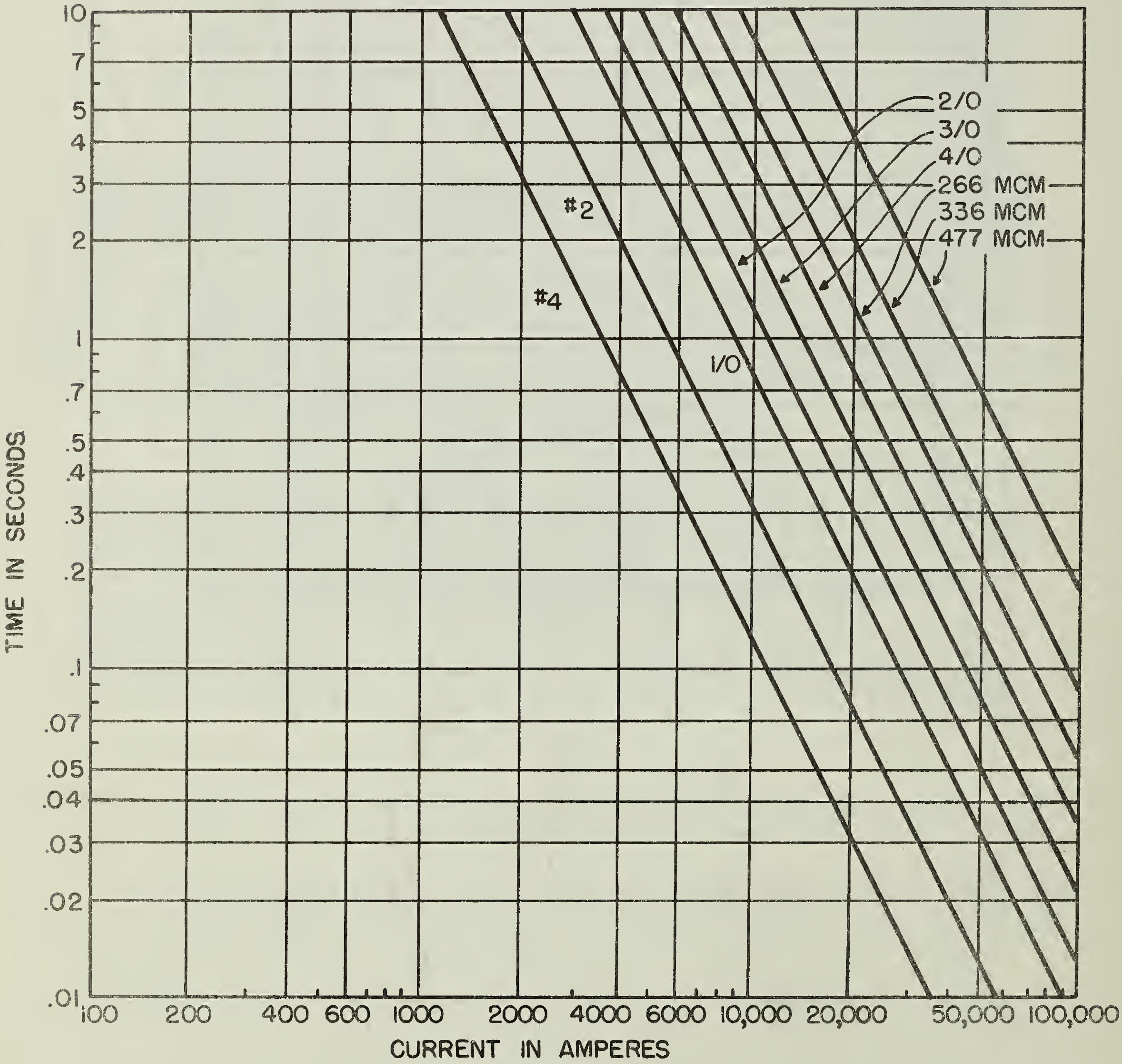


Figure 29

Curves provided by the Aluminum Association.

Fig. 30 - TIME-CURRENT DAMAGE CURVES FOR BARE STRANDED ALUMINUM CONDUCTOR

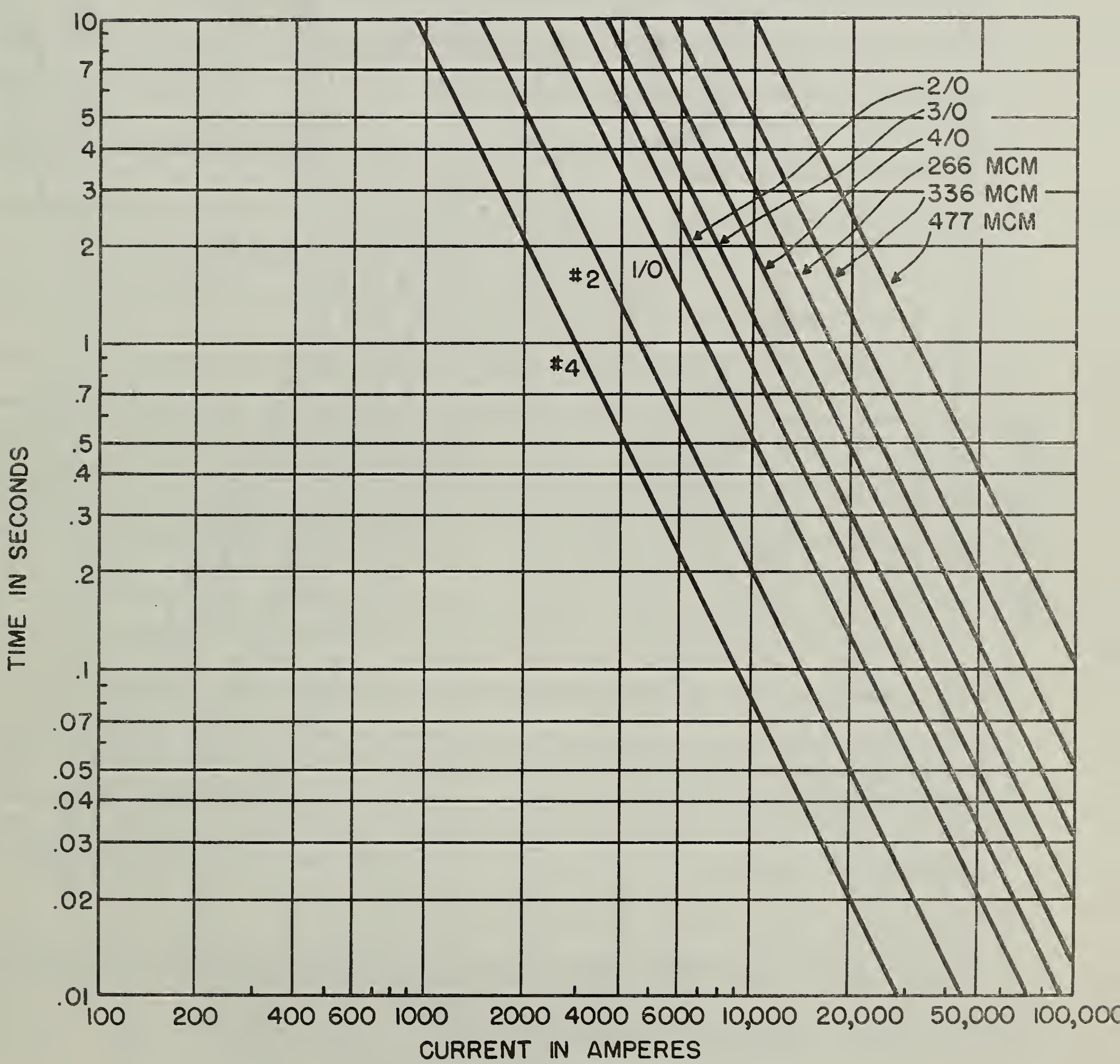


Figure 30

Curves provided by the Aluminum Association.

Time-Current Damage Curve for URD Cable, Aluminum Conductor
High Molecular Weight Polyethylene Insulation
(Maximum Short Circuit Temperature-150° C)

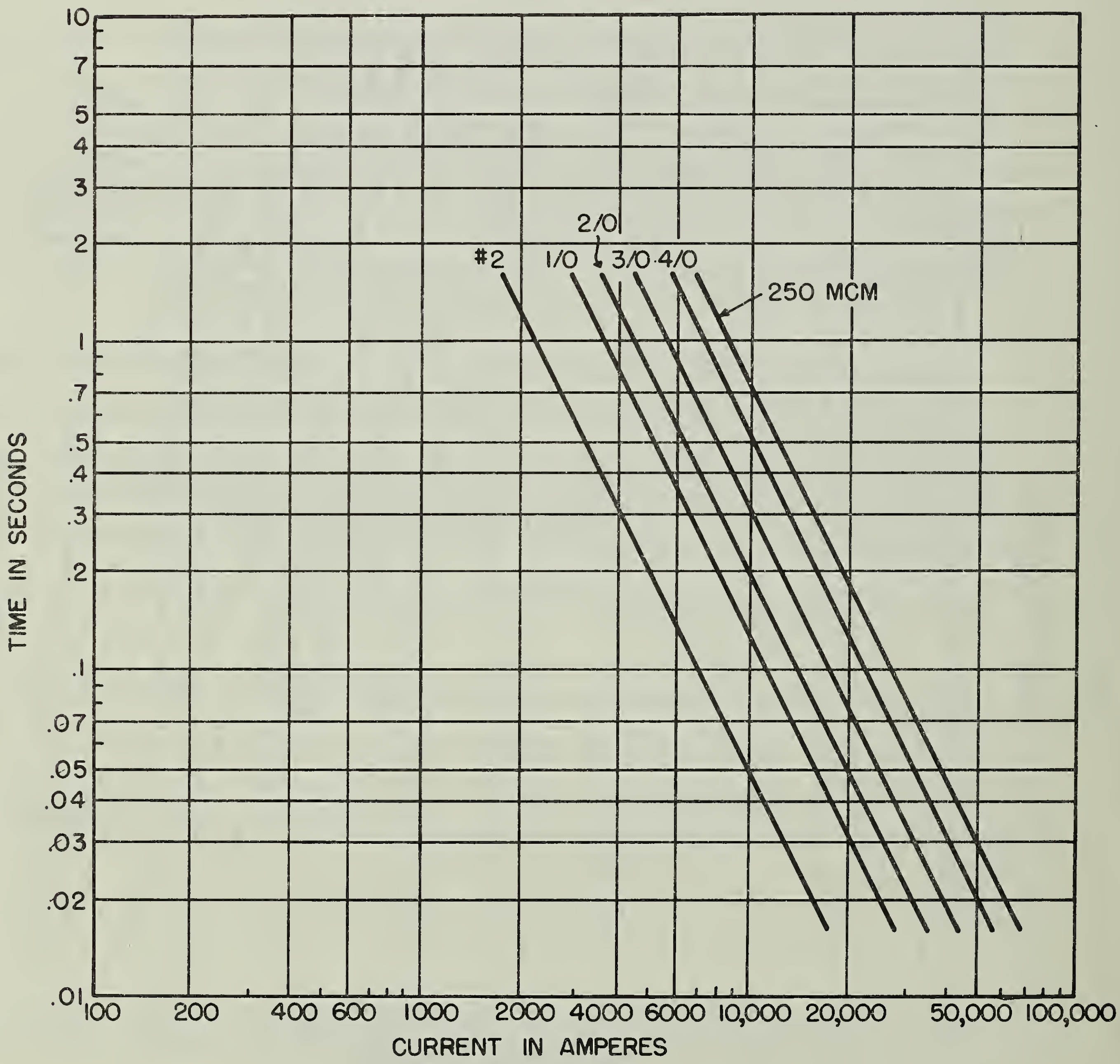


Figure 31

Curves based on IPCEA Publication P-32-382, "Short Circuit Characteristics of Insulated Cable."

TIME-CURRENT DAMAGE CURVE FOR URD CABLE

ALUMINUM CONDUCTOR, CROSS-LINKED POLYETHYLENE INSULATION

(MAXIMUM SHORT CIRCUIT TEMPERATURE-250° C)

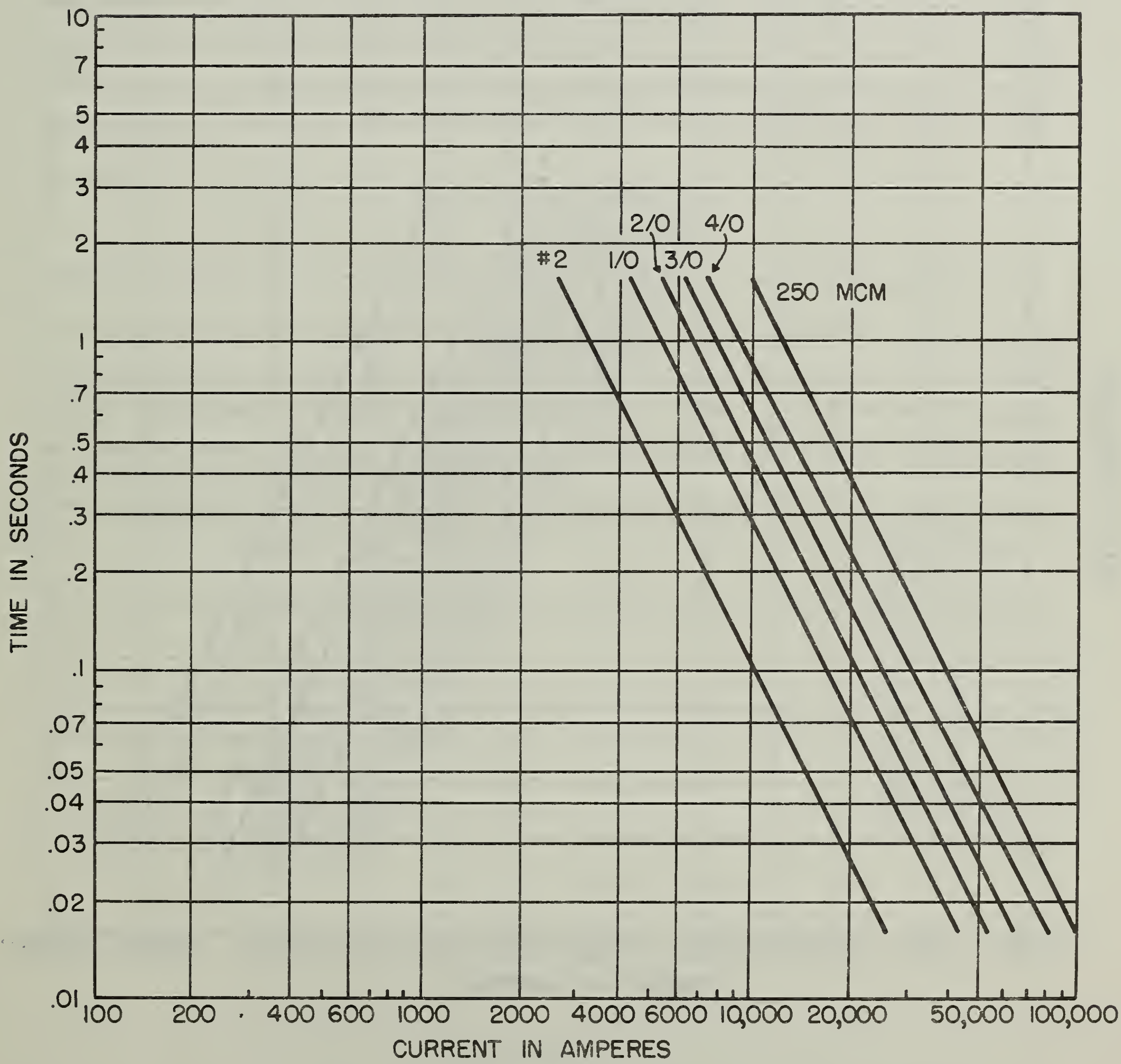


Figure 32

Curves based on IPCEA Publication P-32-382, "Short Circuit Characteristics of Insulated Cable."

TIME-CURRENT DAMAGE CURVES FOR BARE COPPER CONCENTRIC NEUTRAL

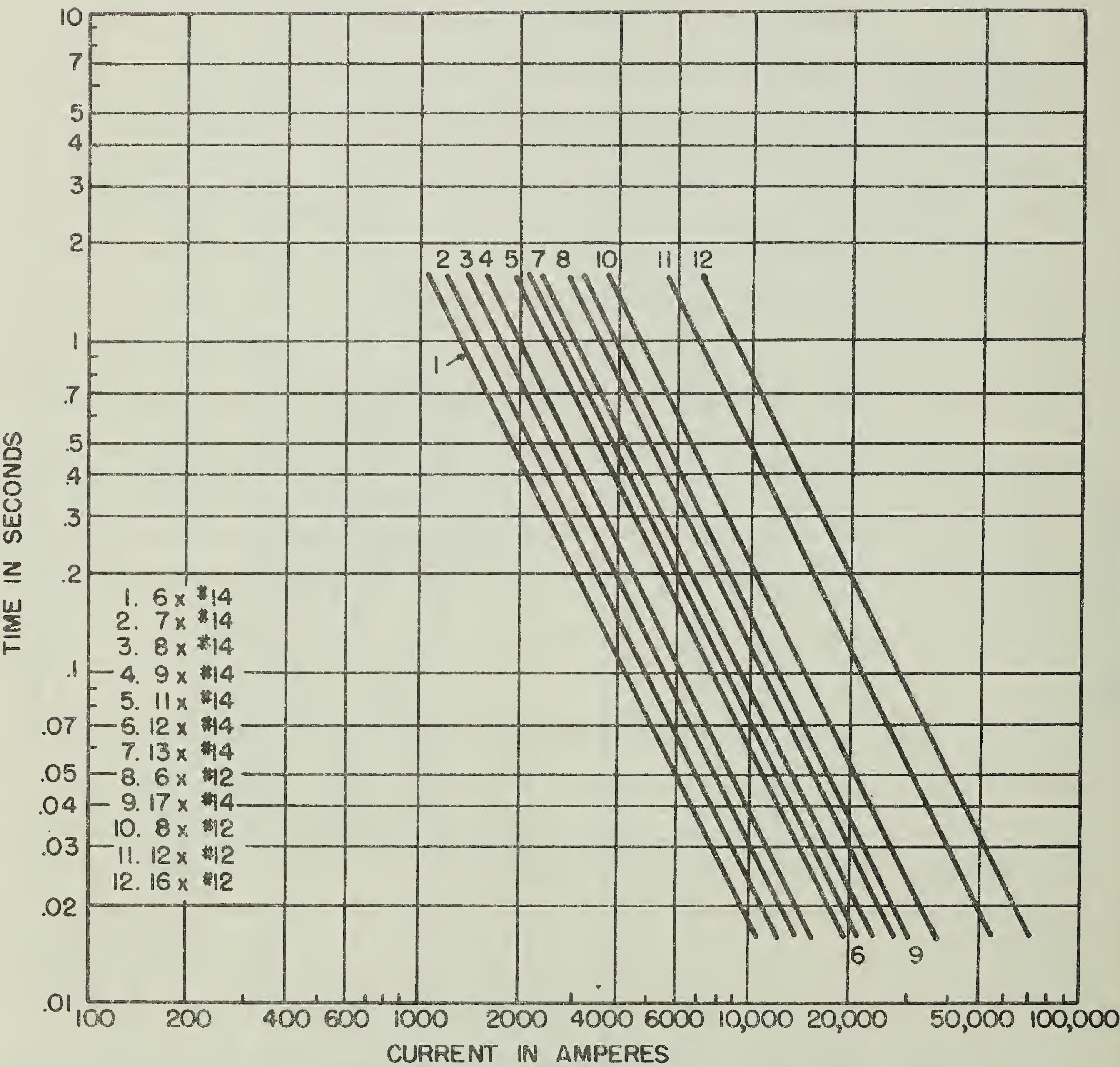


Figure 33

Curves based on the methods used in IPCEA Publication P45-482, "Short-Circuit Performance of Metallic Shielding and Sheaths of Insulated Cable."

☆U.S. GOVERNMENT PRINTING OFFICE: 1978 721-596/766 1-3